

# **Supplementary Income Statement Information**

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2019, 2018 and 2017:

## **2019**

<b>Depreciation and Amortization</b>	<b>AEP</b>	<b>AEP Texas</b>	<b>AEPTCo</b>	<b>APCo</b>	<b>I&amp;M</b>	<b>OPCo</b>	<b>PSO</b>	<b>SWEPCo</b>
<b>(in millions)</b>								
Depreciation and Amortization of Property, Plant and Equipment	\$ 2,203.7	\$ 365.9	\$ 176.0	\$ 466.5	\$ 330.6	\$ 229.4	\$ 162.5	\$ 247.9
Amortization of Certain Securitized Assets	280.7	258.7	—	—	—	22.0	—	—
Amortization of Regulatory Assets and Liabilities	30.1	(2.3)	—	0.3	20.0	(10.5)	7.0	1.2
<b>Total Depreciation and Amortization</b>	<b>\$ 2,514.5</b>	<b>\$ 622.3</b>	<b>\$ 176.0</b>	<b>\$ 466.8</b>	<b>\$ 350.6</b>	<b>\$ 240.9</b>	<b>\$ 169.5</b>	<b>\$ 249.1</b>

## **2018**

<b>Depreciation and Amortization</b>	<b>AEP</b>	<b>AEP Texas</b>	<b>AEPTCo</b>	<b>APCo</b>	<b>I&amp;M</b>	<b>OPCo</b>	<b>PSO</b>	<b>SWEPCo</b>
<b>(in millions)</b>								
Depreciation and Amortization of Property, Plant and Equipment	\$ 1,965.0	\$ 262.2	\$ 133.9	\$ 428.1	\$ 278.9	\$ 232.6	\$ 155.5	\$ 237.0
Amortization of Certain Securitized Assets	287.9	240.0	—	—	—	47.9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0.3	14.2	(20.8)	8.5	2.5
<b>Total Depreciation and Amortization</b>	<b>\$ 2,286.6</b>	<b>\$ 499.6</b>	<b>\$ 133.9</b>	<b>\$ 428.4</b>	<b>\$ 293.1</b>	<b>\$ 259.7</b>	<b>\$ 164.0</b>	<b>\$ 239.5</b>

## **2017**

<b>Depreciation and Amortization</b>	<b>AEP</b>	<b>AEP Texas</b>	<b>AEPTCo</b>	<b>APCo</b>	<b>I&amp;M</b>	<b>OPCo</b>	<b>PSO</b>	<b>SWEPCo</b>
<b>(in millions)</b>								
Depreciation and Amortization of Property, Plant and Equipment	\$ 1,709.1	\$ 221.1	\$ 95.7	\$ 407.6	\$ 203.1	\$ 200.9	\$ 131.4	\$ 217.2
Amortization of Certain Securitized Assets	275.9	231.4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7.8	(19.4)	(1.0)	0.2
<b>Total Depreciation and Amortization</b>	<b>\$ 1,997.2</b>	<b>\$ 450.1</b>	<b>\$ 95.7</b>	<b>\$ 407.9</b>	<b>\$ 210.9</b>	<b>\$ 225.9</b>	<b>\$ 130.4</b>	<b>\$ 217.4</b>

**Supplementary Cash Flow Information (Applies to AEP)**

Cash Flow Information	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	\$ 1,022.5	\$ 939.3	\$ 858.3
Income Taxes	6.1	(24.7)	(1.1)
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	87.5	55.6	60.7
Construction Expenditures Included in Current Liabilities as of December 31,	1,341.1	1,120.4	1,330.8
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0.1	4.0	—
Noncash Contribution of Assets by Noncontrolling Interest	—	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.3	2.2	2.6
Noncontrolling Interest Assumed with Sempra Renewables LLC and Santa Rita East Acquisition	253.4	—	—
Liabilities Assumed with Sempra Renewable LLC and Santa Rita East Acquisition	32.4	—	—

## 2. NEW ACCOUNTING STANDARDS

The disclosures in this note apply to all Registrants unless indicated otherwise.

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following standards will impact the financial statements.

### *ASU 2016-02 "Accounting for Leases" (ASU 2016-02)*

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheets in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheets. See Note 13 - Leases for additional disclosures required by the new standard.

### *ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)*

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting

date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheets. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

### 3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

#### *Presentation of Comprehensive Income*

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2019, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

#### AEPT

For the Year Ended December 31, 2019	Cash Flow Hedges		Pension and OPEB		Total
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	
			(in millions)		
<b>Balance in AOCI as of December 31, 2018</b>	\$ (23.0)	\$ (12.6)	\$ 136.3	\$ (221.1)	\$ (120.4)
Change in Fair Value Recognized in AOCI	(127.2)	(0.2) (a)	—	57.7	(69.7)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (b)	(0.2)	—	—	—	(0.2)
Purchased Electricity for Resale (b)	59.5	—	—	—	59.5
Interest Expense (b)	—	1.5	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—	12.1	—	12.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59.3	1.5	(7.1)	—	53.7
Income Tax (Expense) Benefit	12.6	0.2	(1.5)	—	11.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	46.7	1.3	(5.6)	—	42.4
Net Current Period Other Comprehensive Income (Loss)	(80.5)	1.1	(5.6)	57.7	(27.3)
<b>Balance in AOCI as of December 31, 2019</b>	<u>\$ (103.5)</u>	<u>\$ (11.5)</u>	<u>\$ 130.7</u>	<u>\$ (163.4)</u>	<u>\$ (147.7)</u>

**AEP**

For the Year Ended December 31, 2018	Cash Flow Hedges		Securities Available for Sale	Pension and OPEB		Total
	Commodity	Interest Rate		Amortization of Deferred Costs	Changes in Funded Status	
			(in millions)			
<b>Balance in AOCI as of December 31, 2017</b>	\$ (28.4)	\$ (13.0)	\$ 11.9	\$ 141.6	\$ (179.9)	\$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (b)	(32.6)	—	—	—	—	(32.6)
Interest Expense (b)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
ASU 2018-02 Adoption	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption	—	—	(11.9)	—	—	(11.9)
<b>Balance in AOCI as of December 31, 2018</b>	<u>\$ (23.0)</u>	<u>\$ (12.6)</u>	<u>\$ —</u>	<u>\$ 136.3</u>	<u>\$ (221.1)</u>	<u>\$ (120.4)</u>

  

For the Year Ended December 31, 2017	Cash Flow Hedges		Securities Available for Sale	Pension and OPEB		Total
	Commodity	Interest Rate		Amortization of Deferred Costs	Changes in Funded Status	
			(in millions)			
<b>Balance in AOCI as of December 31, 2016</b>	\$ (23.1)	\$ (15.7)	\$ 8.4	\$ 140.5	\$ (266.4)	\$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (b)	28.8	—	—	—	—	28.8
Interest Expense (b)	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains) Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Benefit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
<b>Balance in AOCI as of December 31, 2017</b>	<u>\$ (28.4)</u>	<u>\$ (13.0)</u>	<u>\$ 11.9</u>	<u>\$ 141.6</u>	<u>\$ (179.9)</u>	<u>\$ (67.8)</u>

AEP Texas

For the Year Ended December 31, 2019	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2018</b>	\$ (4.4)	\$ 4.7	\$ (15.4)	\$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	1.1	2.3
<b>Balance in AOCI as of December 31, 2019</b>	<u>\$ (3.4)</u>	<u>\$ 4.9</u>	<u>\$ (14.3)</u>	<u>\$ (12.8)</u>

For the Year Ended December 31, 2018	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2017</b>	\$ (4.5)	\$ 4.5	\$ (12.6)	\$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption	(0.9)	—	(1.8)	(2.7)
<b>Balance in AOCI as of December 31, 2018</b>	<u>\$ (4.4)</u>	<u>\$ 4.7</u>	<u>\$ (15.4)</u>	<u>\$ (15.1)</u>

For the Year Ended December 31, 2017	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2016</b>	\$ (5.4)	\$ 4.2	\$ (13.7)	\$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1

Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.4	—	1.7
Income Tax (Expense) Benefit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
<b>Balance in AOCI as of December 31, 2017</b>	<b>\$ (4.5)</b>	<b>\$ 4.5</b>	<b>\$ (12.6)</b>	<b>\$ (12.6)</b>

APCo

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB		Total
		Amortization of Deferred Costs	Changes in Funded Status	
		(in millions)		
Balance in AOCI as of December 31, 2018	\$ 1 8	\$ 11.7	\$ (18 5)	\$ (5 0)
Change in Fair Value Recognized in AOCI	—	—	13 4	13 4
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1 1)	—	—	(1 1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	2 1	—	2 1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1 1)	(3 2)	—	(4.3)
Income Tax (Expense) Benefit	(0 2)	(0 7)	—	(0 9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0 9)	(2 5)	—	(3 4)
Net Current Period Other Comprehensive Income (Loss)	(0 9)	(2 5)	13 4	10 0
Balance in AOCI as of December 31, 2019	\$ 0 9	\$ 9.2	\$ (5.1)	\$ 5 0

For the Year Ended December 31, 2018	Cash Flow Hedges		Pension and OPEB		Total
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	
(in millions)					
Balance in AOCI as of December 31, 2017	\$ —	\$ 2.2	\$ 14.8	\$ (15.7)	\$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (b)	0.9	—	—	—	0.9
Interest Expense (b)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	\$ —	\$ 1.8	\$ 11.7	\$ (18.5)	\$ (5.0)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB		Total
		Amortization of Deferred Costs	Changes in Funded Status	
		(in millions)		

<b>Balance in AOCI as of December 31, 2016</b>	<b>\$ 2.9</b>	<b>\$ 16.0</b>	<b>\$ (27.3)</b>	<b>\$ (8.4)</b>
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Benefit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
<b>Balance in AOCI as of December 31, 2017</b>	<b>\$ 2.2</b>	<b>\$ 14.8</b>	<b>\$ (15.7)</b>	<b>\$ 1.3</b>

**I&M**

For the Year Ended December 31, 2019	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2018</b>	\$ (11.5)	\$ 5.1	\$ (7.4)	\$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	0.8	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.2)	—	1.8
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.2)	—	1.4
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.2)	0.8	2.2
<b>Balance in AOCI as of December 31, 2019</b>	<b>\$ (9.9)</b>	<b>\$ 4.9</b>	<b>\$ (6.6)</b>	<b>\$ (11.6)</b>

For the Year Ended December 31, 2018	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2017</b>	\$ (10.7)	\$ 5.1	\$ (6.5)	\$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption	(2.4)	—	(0.3)	(2.7)
<b>Balance in AOCI as of December 31, 2018</b>	<b>\$ (11.5)</b>	<b>\$ 5.1</b>	<b>\$ (7.4)</b>	<b>\$ (13.8)</b>

For the Year Ended December 31, 2017	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
<b>Balance in AOCI as of December 31, 2016</b>	\$ (12.0)	\$ 5.1	\$ (9.3)	\$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8

Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
<b>Balance in AOCI as of December 31, 2017</b>	<b>\$ (10.7)</b>	<b>\$ 5.1</b>	<b>\$ (6.5)</b>	<b>\$ (12.1)</b>

**OPCo**

<b>For the Year Ended December 31, 2019</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2018</b>		<b>\$ 1.0</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.3)
Income Tax (Expense) Benefit		(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.0)
Net Current Period Other Comprehensive Income (Loss)		(1.0)
<b>Balance in AOCI as of December 31, 2019</b>		<b>\$ —</b>
<b>For the Year Ended December 31, 2018</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2017</b>		<b>\$ 1.9</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.7)
Income Tax (Expense) Benefit		(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.3)
Net Current Period Other Comprehensive Income (Loss)		(1.3)
ASU 2018-02 Adoption		0.4
<b>Balance in AOCI as of December 31, 2018</b>		<b>\$ 1.0</b>
<b>For the Year Ended December 31, 2017</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2016</b>		<b>\$ 3.0</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.7)
Income Tax (Expense) Benefit		(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.1)
Net Current Period Other Comprehensive Income (Loss)		(1.1)
<b>Balance in AOCI as of December 31, 2017</b>		<b>\$ 1.9</b>

**PSO**

<b>For the Year Ended December 31, 2019</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2018</b>		<b>\$ 2.1</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.3)
Income Tax (Expense) Benefit		(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.0)
Net Current Period Other Comprehensive Income (Loss)		(1.0)
<b>Balance in AOCI as of December 31, 2019</b>		<b>\$ 1.1</b>
<b>For the Year Ended December 31, 2018</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2017</b>		<b>\$ 2.6</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.3)
Income Tax (Expense) Benefit		(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(1.0)
Net Current Period Other Comprehensive Income (Loss)		(1.0)
ASU 2018-02 Adoption		0.5
<b>Balance in AOCI as of December 31, 2018</b>		<b>\$ 2.1</b>
<b>For the Year Ended December 31, 2017</b>		<b>Cash Flow Hedge – Interest Rate</b>
		<b>(in millions)</b>
<b>Balance in AOCI as of December 31, 2016</b>		<b>\$ 3.4</b>
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (b)		(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(1.3)
Income Tax (Expense) Benefit		(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(0.8)
Net Current Period Other Comprehensive Income (Loss)		(0.8)
<b>Balance in AOCI as of December 31, 2017</b>		<b>\$ 2.6</b>

**SWEPCo**

For the Year Ended December 31, 2019	Pension and OPEB			
	Cash Flow Hedge – Interest Rate	Amortization	Changes in	Total
		of Deferred Costs	Funded Status	
		(in millions)		
Balance in AOCI as of December 31, 2018	\$ (3.3)	\$ (0.2)	\$ (1.9)	\$ (5.4)
Change in Fair Value Recognized in AOCI	—	—	3.7	3.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.4)	—	0.5
Income Tax (Expense) Benefit	0.4	(0.3)	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.1)	—	0.4
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.1)	3.7	4.1
Balance in AOCI as of December 31, 2019	\$ (1.8)	\$ (1.3)	\$ 1.8	\$ (1.3)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB		Total
		Amortization of Deferred Costs	Changes in Funded Status	
		(in millions)		
Balance in AOCI as of December 31, 2017	\$ (6.0)	\$ 1.2	\$ 0.8	\$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	(3.1)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.1	—	—	2.1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1.8)	—	0.3
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4.0	(1.4)	(3.1)	(0.5)
ASU 2018-02 Adoption	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	\$ (3.3)	\$ (0.2)	\$ (1.9)	\$ (5.4)

		Pension and OPEB		
	Cash Flow Hedge –	Amortization	Changes in	
	Interest Rate	of Deferred	Funded	
For the Year Ended December 31, 2017		Costs	Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	\$ (7.4)	\$ 1.9	\$ (3.9)	\$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4.7	4.7

Amount of (Gain) Loss Reclassified from AOCI

Interest Expense (b)	2.2	—	—	2.2
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.2	(1.1)	—	1.1
Income Tax (Expense) Benefit	0.8	(0.4)	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.4	(0.7)	—	0.7
Net Current Period Other Comprehensive Income (Loss)	1.4	(0.7)	4.7	5.4
<b>Balance in AOCI as of December 31, 2017</b>	<b>\$ (6.0)</b>	<b>\$ 1.2</b>	<b>\$ 0.8</b>	<b>\$ (4.0)</b>

- (a) The change in fair value includes \$4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the year ended December 31, 2019. See "Sempra Renewables LLC" section of Note 17 for additional information.
- (b) Amounts reclassified to the referenced line item on the statements of income.

#### **4. RATE MATTERS**

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

##### **Impact of Tax Reform**

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 12 - Income Taxes.

##### **AEP Texas Rate Matters (Applies to AEP and AEP Texas)**

###### ***2019 Texas Base Rate Case***

In May 2019, AEP Texas filed a request with the PUCT for a \$56 million annual increase in rates based upon a proposed 10.5% return on common equity. The filing includes a proposed Income Tax Refund Rider that will refund \$21 million annually of Excess ADIT that is primarily not subject to normalization requirements. The rate case also seeks a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019. As of December 31, 2019, AEP Texas' cumulative revenues from transmission and distribution interim rate increases are estimated to be approximately \$1.4 billion and are subject to reconciliation in this base rate case.

In November 2019, ALJs issued a Proposal for Decision recommending a \$60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs also recommended disallowances that could potentially result in write-offs of \$84 million related to capital incentives and \$5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments.

In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of \$40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of \$26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of \$23 million related to capital investments recorded through 2018 and \$4 million related to rate case expenses. In addition, AEP Texas will refund: (a) \$77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) \$31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) \$30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. Per the agreement, AEP Texas is required to file its next base rate case within four years of the date of the final order. The agreement also: (a) states future financially based capital incentives will not be included in interim transmission and distribution rates, (b) contains various ring-fencing provisions and (c) will allow the PUCT to decide whether to adopt a dividend restriction ring-fencing provision.

As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of \$33 million in December 2019 related to capital investments, which included \$10 million of current year investments, in Asset Impairments and Other Related Charges on the statements of income, (b) recorded a \$30 million provision for refund on the statements of income for revenues previously collected through rates and (c) wrote-off \$4 million of rate case expenses to Other Operation on the statements of income. The PUCT is expected to issue an order in the first quarter of 2020. Upon approval of the 2019 Texas Base Rate Case, AEP Texas will refund \$275 million of Excess ADIT associated with certain depreciable property using ARAM to transmission customers. AEP Texas will determine how



to refund the remaining Excess ADIT that is not subject to normalization requirements in future proceedings. If the final order from the PUCT requires refunds or authorizes disallowances in excess of the amounts included within the February 2020 stipulation and settlement agreement, it could reduce future net income and cash flows and impact financial condition.

### ***Texas Storm Cost Securitization***

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In March 2019, AEP Texas filed a request to securitize total estimated distribution-related system restoration costs with the PUCT, which included estimated carrying costs. In June 2019, the PUCT approved the financing order. As part of the financing order, AEP Texas agreed to offset \$64 million of Excess ADIT that is not subject to normalization requirements against the total distribution-related system restoration costs. In September 2019, AEP Texas issued \$235 million of securitization bonds. The securitization bonds included carrying costs of \$33 million, which includes \$21 million of debt carrying costs recorded as a reduction to Interest Expense in 2019.

The stipulation and settlement agreement discussed in the 2019 Texas Base Rate Case above does not require any adjustments to the remaining \$95 million of estimated net transmission-related system restoration costs and these costs will be recovered in base rates if the agreement is approved by the PUCT. If these costs are not recovered, it could have an adverse effect on future net income, cash flows and financial condition.

### **APCo and WPCo Rate Matters (Applies to AEP and APCo)**

#### ***Virginia Legislation Affecting Earnings Reviews***

Under a 2015 amended Virginia law, APCo's existing generation and distribution base rates were frozen until after the Virginia SCC ruled on APCo's next biennial review. The 2015 amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

Further amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 earnings test years (triennial review). Triennial reviews are subject to an earnings test which provides that 70% of any earnings in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. In such case, the Virginia SCC could also lower APCo's Virginia retail base rates on a prospective basis. In November 2018, the Virginia SCC authorized a ROE of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period.

Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. In 2015, APCo retired the Sporn Plant, the Kanawha River Plant, the Glen Lyn Plant, Clinch River Unit 3 and the coal portions of Clinch River Units 1 and 2 (collectively, the retired coal-fired generation assets). The net book value of these plants at the retirement date was \$93 million before cost of removal, including materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of \$93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately \$51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Inclusive of the \$93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range. If any APCo Virginia jurisdictional costs are not recoverable or refunds of revenues collected from customers during the triennial review period, it could reduce future net income and cash flows and impact financial condition.

### ***Virginia Staff Depreciation Study Request***

In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a \$21 million pretax increase in annual depreciation expense (\$6 million related to transmission) with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of the Virginia SCC's Triennial Review of APCo's earnings, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review. If the Virginia SCC were to issue an order approving the Virginia staff's recommended retroactive change in APCo's Virginia depreciation rates, it would reduce future net income and cash flows and impact financial condition.

### ***Virginia Tax Reform***

In March 2019, the Virginia SCC issued an order to reduce APCo's base rates to refund: (a) \$40 million annually for ongoing annual tax savings, (b) \$9 million annually of Excess ADIT associated with certain depreciable property using ARAM, (c) \$94 million of Excess ADIT that is not subject to normalization requirements over three years and (d) a one-time credit of \$22 million for estimated excess taxes collected from customers as a result of Tax Reform during the 15-month period ending March 31, 2019.

### ***2018 West Virginia Base Rate Case***

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by \$115 million (\$98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase included \$32 million (\$28 million related to APCo) due to increased annual depreciation expense and reflected the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a \$95 million (\$80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of West Virginia Tax Reform.

In February 2019, the WVPSC issued an order approving a stipulation and settlement agreement between APCo, WPCo, WVPSC staff and certain intervenors. The agreement included an annual base rate increase of \$44 million (\$36 million related to APCo) based upon a 9.75% return on common equity effective March 2019. The agreement also included: (a) \$18 million (\$14 million related to APCo) of increased annual depreciation expense, (b) a \$24 million refund (\$19 million related to APCo) over two years, through a rider beginning March 2019, of Excess ADIT that is not subject to normalization requirements, (c) the utilization of \$14 million (\$12 million related to APCo) of Excess ADIT that is not subject to normalization requirements to offset regulatory asset balances relating to ENEC, (d) an agreement to seek WVPSC approval of economic incentive programs to provide funds to aid in industrial and commercial development and (e) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020.

## **ETT Rate Matters (Applies to AEP)**

### ***ETT Interim Transmission Rates***

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on semi-annual interim rate changes which are subject to review and possible true-up in the next base rate proceeding. Through December 31, 2019, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be \$1 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for base rate proceedings. The rule requires ETT to file for a comprehensive base rate review no later than February 1, 2021.

## **I&M Rate Matters (Applies to AEP and I&M)**

### ***Michigan Tax Reform***

In October 2018, I&M made a filing with the MPSC recommending to: (a) refund Excess ADIT associated with certain depreciable property using ARAM and (b) refund Excess ADIT that is not subject to normalization requirements over ten years. In November 2019, the MPSC issued an order authorizing I&M to: (a) refund \$48 million of Excess ADIT associated with certain depreciable property using ARAM and (b) refund \$28 million of Excess ADIT that is not subject to normalization requirements over ten years. In January 2020, the MPSC issued an order in the 2019 Michigan Base Rate Case that changed the refund period from ten years to five years. See "2019 Michigan Base Rate Case" below.

### ***2019 Indiana Base Rate Case***

In May 2019, I&M filed a request with the IURC for a \$172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes \$78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes \$52 million related to proposed investments and \$26 million related to increased depreciation rates. The request includes the continuation of all existing riders and a new Automated Metering Infrastructure (AMI) rider for proposed meter projects.

In August 2019, various intervenors filed testimony that recommended annual rate increases ranging from \$2 million to \$33 million based upon a return on common equity ranging from 9% to 9.73%. The difference between I&M's requested annual base rate increase and the intervenor's recommendations are primarily due to: (a) proposed denial of return on and of certain new plant investments, (b) proposed lower depreciation rates, (c) a reduction in the requested return on common equity and (d) exclusion of I&M's proposed re-allocation of capacity costs related to I&M's June 2020 loss of a significant FERC wholesale contract. In addition, certain intervenors recommended disallowances that could potentially result in write-offs of \$41 million related to the remaining book value of existing Indiana jurisdictional meters if I&M is approved to deploy AMI meters as initially requested and \$11 million associated with certain Cook Plant study costs.

In September 2019, I&M filed testimony rebutting the various intervenors' recommendations. In October 2019, a hearing at the IURC was held. The IURC is expected to issue an order on this case in the first quarter of 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

### ***2019 Michigan Base Rate Case***

In June 2019, I&M filed a request with the MPSC for a \$58 million annual increase. The requested increase in Michigan rates would be phased in through June 2020 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes \$19 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes \$13 million related to proposed investments and \$6 million related to increased depreciation rates. The proposed annual increase also includes \$10 million for annual lost revenue related to the Michigan Electric Customer Choice Program that began in 2019.

In January 2020, the MPSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of \$36 million based upon a 9.86% return on common equity effective with the first billing cycle of February 2020. The order also requires I&M to amortize and refund to customers through I&M Michigan base rates: (a) Excess ADIT that is not subject to normalization (over a period of five years starting February 2020) and (b) Excess ADIT associated with certain depreciable property using ARAM. Additionally, the order states that I&M will not be allowed to file its next base rate case before 2022.

### **OPCo Rate Matters (Applies to AEP and OPCo)**

#### ***Ohio ESP Filings***

In 2016, OPCo filed a proposal to extend the ESP through May 2024. In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. In January 2020, the Ohio Supreme Court affirmed the PUCO order, rejecting the filed appeal.

OPCo's Enhanced Service Reliability Rider (ESRR) authorized under the ESP is subject to annual audits. In May 2018, the PUCO staff filed comments indicating that 2016 spending under the ESRR was subject to authorized limits and that OPCo overspent those limits. In March 2019, the PUCO staff filed additional comments that OPCo overspent the authorized limit in 2017. Management believes that both 2016 and 2017 ESRR spending is not subject to an authorized limit and that a spending limit was not established until 2018, as part of the ESP extension. A hearing was held in May 2019 to address the 2016 audit. In December 2019, the PUCO issued an order finding that OPCo's 2016 ESRR spending was not subject to an authorized limit. If it is determined OPCo did have an authorized spending limit under the ESRR in 2017, and refunds are ordered, it would reduce future net income and cash flows and impact financial condition.

#### ***2016 SEET Filing***

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

In 2016, OPCo recorded a 2016 SEET provision of \$58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of Retail Stability Rider costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In February 2019, the PUCO issued an order that OPCo did not have significantly excessive earnings in 2016. As a result of the order, OPCo reversed the \$58 million provision in the first quarter of 2019.

## **PSO Rate Matters (Applies to AEP and PSO)**

### ***2018 Oklahoma Base Rate Case***

In 2018, PSO filed a request with the OCC for an \$88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance-based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase included \$13 million related to increased annual depreciation rates and \$7 million related to increased storm expense amortization. The requested increase in annual depreciation rates included the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020.

In March 2019, the OCC issued an order approving a stipulation and settlement agreement for a \$46 million annual increase, based on a 9.4% return on equity effective with the first billing cycle of April 2019. The order also included agreements between the parties that: (a) depreciation rates will remain unchanged, (b) PSO will file a new base rate request no earlier than October 2020 and no later than October 2021 and (c) PSO will refund Excess ADIT that is not subject to normalization requirements over five years instead of the ten years ordered in the Oklahoma Tax Reform case. The order did not approve the performance-based rate plan but instead provided for an expansion of the SPP Transmission Tariff that tracks previously untracked SPP costs and a new Distribution Reliability and Safety Rider that provides additional revenues capped at \$5 million per year for distribution projects related to safety and reliability that are not normal distribution replacements.

## **SWEP Co Rate Matters (Applies to AEP and SWEP Co)**

### ***2012 Texas Base Rate Case***

In 2012, SWEP Co filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEP Co's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEP Co reversed \$114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately \$52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEP Co and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEP Co filed its response to these replies. In the fourth quarter of 2019 and first quarter of 2020, SWEP Co and various intervenors filed briefs with the Texas Supreme Court.

As of December 31, 2019, the net book value of Turk Plant was \$1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEP Co cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

### ***2016 Texas Base Rate Case***

In 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of \$69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of \$50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in-service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of \$2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of \$19 million, which included \$7 million associated with the lack of return on Welsh Plant, Unit 2 and \$12 million related to other disallowed plant investments, (b) recognized \$32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional \$7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The \$32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

### ***2018 Louisiana Formula Rate Filing***

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net \$28 million annual increase, which was effective August 2018 and included SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to \$18 million. The difference between SWEPCo's requested \$28 million annual increase and the \$18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund \$11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. In June 2019, the LPSC staff issued its report which reaffirmed its \$11 million refund recommendation. The report also contends that SWEPCo's requested annual rate increase of \$18 million, which was implemented in August 2018, is overstated by \$4 million and proposes an annual rate increase of \$14 million. Additionally, the report recommends SWEPCo refund the excess over-collections associated with the \$4 million difference for the period of August 2018 through the implementation of new rates. In July 2019, the LPSC approved the \$11 million refund. A decision by the LPSC on the remaining formula rate plan issues is expected in the first half of 2020.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

### ***Welsh Plant - Environmental Impact***

Management currently estimates that the investment necessary to meet environmental regulations for Welsh Plant, Units 1 and 3 could total approximately \$520 million, excluding AFUDC. As of December 31, 2019, SWEPCo had incurred costs of \$399 million, including AFUDC, related to these projects. SWEPCo has received approval to recover \$340 million of its in-service investments related to environmental controls installed at Welsh Plant through base rates in its Arkansas, Louisiana and Texas jurisdictions. SWEPCo also recovers a portion of its investments related to environmental controls installed at Welsh Plant through wholesale formula rates. See "2016 Texas Base Rate Case," "2018 Louisiana Formula Rate Filing" and "2019 Arkansas Base Rate Case" disclosures for additional information. SWEPCo will seek recovery of future costs that have not yet been approved through base rate cases. If any of the remaining costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.



### ***2019 Arkansas Base Rate Case***

In February 2019, SWEPCo filed a request with the APSC for a \$75 million increase in Arkansas base rates based upon a proposed 10.5% return on common equity. The filing requested rate base treatment for the Stall Plant and environmental retrofits that were being recovered through riders. Eliminating these riders would result in a net annual requested base rate increase of \$58 million. The proposed net annual increase included \$12 million related to vegetation management to improve the reliability of its Arkansas distribution system. The filing also provided notice of SWEPCo's proposal to have its rates regulated under the formula rate review mechanism authorized by Arkansas law, including a Formula Rate Review Rider. In October 2019, SWEPCo reduced its requested base rate increase from \$75 million to \$67 million.

In December 2019, the APSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of \$53 million (\$24 million net of amounts currently recovered through riders) based upon a 9.45% return on common equity. The order modified the stipulation and settlement agreement and included a disallowance of \$4 million for previously recorded capital incentives. The base rate increase includes \$6 million for increased annual depreciation expense and became effective with the first billing cycle in January 2020. The order provides recovery for: (a) the Stall Plant, (b) environmental retrofit projects and (c) the remaining net book value, with a debt return for investors, of Welsh Unit 2. The order also states that SWEPCo's rates will be regulated under the formula rate mechanism authorized by Arkansas law, which includes a Formula Rate Review Rider. Additionally, SWEPCo agreed to make the necessary filings with the APSC, at least 12 months in advance, to seek regulatory approval to retire the Dolet Hills Power Station no later than December 31, 2026.

### **FERC Rate Matters**

#### ***FERC Transmission Complaint - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)***

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) required AEP's transmission owning subsidiaries within PJM to provide a one-time refund of \$50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increased the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

#### ***FERC Transmission Complaint - AEP's SPP Participants (Applies to AEP, AEPTCo, PSO and SWEPCo)***

In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. In June 2019, the FERC approved an unopposed settlement agreement between AEP's transmission owning subsidiaries within SPP and the complainants. The settlement agreement established a base ROE of 10% (10.50% inclusive of the RTO incentive adder of 0.5%) effective January 1, 2019. Additionally, refunds including carrying charges were made



from the date of the first complaint through December 31, 2018. Refunds for the period prior to 2019 were made at the time of the 2019 true-up of 2018 rates. Refunds from January 2019 onward will conclude with the 2020 true-up of 2019 rates.

***Modifications to AEP's SPP Transmission Rates (Applies to AEP, AEPTCo, PSO and SWEPCo)***

In 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. The FERC accepted the proposed modifications effective January 1, 2018, subject to refund. In February 2019, AEP's transmission owning subsidiaries within SPP filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In June 2019, the FERC approved the settlement agreement.

## 5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

### ***Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)***

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. See “2018 Oklahoma Base Rate Case” for additional information.

In January 2020, management announced that the Dolet Hills Power Station is probable of abandonment and is to be retired by December 2026. See “Dolet Hills Lignite Company Operations” section of Executive Overview, “2019 Arkansas Base Rate Case” section of Note 4, and “DHLC” section of Note 17 for additional information.

The table below summarizes the plant investments and their cost of removal, currently being recovered, as well as regulatory assets for accelerated depreciation for the generating units as of December 31, 2019.

Plant	Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset		Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
(dollars in millions)									
Oklaunion Power Station	\$ 106.7	\$ 86.6	\$ 20.1	\$ 27.4	(a)	\$ 3.2	\$ 5.1	2020	27 years
Dolet Hills Power Station	338.9	194.2	144.7	—	(b)	5.8	23.6	2026	27 years

- (a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station. See “2018 Oklahoma Base Rate Case” section of Note 4 for additional information.
- (b) Beginning in January 2020, SWEPCo began recording a regulatory asset for accelerated depreciation.

### ***Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)***

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo’s settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo’s share of the net investment in the Dolet Hills Power Station is \$157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of \$106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of \$22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

---

## Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2019	2018	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	\$ 44.7	\$ 101.7	1 year
Under-recovered Fuel Costs - does not earn a return	48.2	48.4	1 year
Total Current Regulatory Assets	\$ 92.9	\$ 150.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	\$ 35.2	\$ 50.3	
Kentucky Deferred Purchased Power Expenses	30.2	14.5	
Oklahoma Power Station Accelerated Depreciation	27.4	5.5	
Other Regulatory Assets Pending Final Regulatory Approval	0.7	9.3	
Total Regulatory Assets Currently Earning a Return	93.5	79.6	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Vegetation Management Program - AEP Texas (a)	29.4	—	
Cook Plant Study Costs	7.6	—	
Storm-Related Costs (b)	7.2	152.4	
Asset Retirement Obligation - Louisiana	7.2	5.3	
Other Regulatory Assets Pending Final Regulatory Approval	6.7	15.4	
Total Regulatory Assets Currently Not Earning a Return	88.2	208.4	
Total Regulatory Assets Pending Final Regulatory Approval (c)	181.7	288.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	690.5	680.9	23 years
Plant Retirement Costs - Asset Retirement Obligation Costs	87.4	64.3	21 years
Meter Replacement Costs	65.4	74.4	8 years
Environmental Control Projects	41.0	43.4	21 years
Cook Plant Upgrade Project	32.6	35.0	14 years
Ohio Distribution Decoupling	31.4	12.3	2 years
Advanced Metering System	26.5	45.3	2 years
Storm-Related Costs	21.3	31.1	3 years
Mitchell Plant Transfer - West Virginia	16.2	17.0	21 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years

Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	<u>48.4</u>	<u>46.1</u>	various
<b>Total Regulatory Assets Currently Earning a Return</b>	<u>1,089.2</u>	<u>1,139.5</u>	

**Regulatory Assets Currently Not Earning a Return**

Pension and OPEB Funded Status	1,309.8	1,326.6	11 years
Unamortized Loss on Reacquired Debt	129.0	134.2	29 years
Unrealized Loss on Forward Commitments	106.8	104.6	13 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Vegetation Management - West Virginia	43.6	26.6	2 years
Postemployment Benefits	34.2	35.6	4 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28.8	21.6	23 years
Medicare Subsidy	23.2	27.9	5 years
Peak Demand Reduction/Energy Efficiency	18.6	31.9	7 years
PJM/SPP Annual Formula Rate True Up	7.3	22.0	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	122.8	94.3	various
<b>Total Regulatory Assets Currently Not Earning a Return</b>	<u>1,887.9</u>	<u>1,882.9</u>	
<b>Total Regulatory Assets Approved for Recovery</b>	<u>2,977.1</u>	<u>3,022.4</u>	
<b>Total Noncurrent Regulatory Assets</b>	<u>\$ 3,158.8</u>	<u>\$ 3,310.4</u>	

- (a) Includes \$26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.
- (b) In September 2019, AEP Texas securitized \$235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See “Texas Storm Cost Securitization” section of Note 4 - Rate Matters for additional information.
- (c) In 2015, APCo recorded a \$91 million reduction, before cost of removal which was \$11 million and \$20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo’s Virginia jurisdiction. The net book value of these plants at the retirement date was \$93 million before cost of removal, including materials and supplies inventory. Based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of \$93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately \$51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

	AEP		
	December 31,		Remaining
	2019	2018	
	(in millions)		Refund Period
<b>Current Regulatory Liabilities</b>			
Over-recovered Fuel Costs - pays a return	\$ 77.5	\$ 35.7	1 year
Over-recovered Fuel Costs - does not pay a return	9.1	22.9	1 year
<b>Total Current Regulatory Liabilities</b>	<b>\$ 86.6</b>	<b>\$ 58.6</b>	
<b>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>			
<b>Regulatory liabilities pending final regulatory determination:</b>			
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Other Regulatory Liabilities Pending Final Regulatory Determination	\$ 0.2	\$ 0.2	
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	<b>0.2</b>	<b>0.2</b>	
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	571.8	1,025.3	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	291.0	695.0	(c) (g)
<b>Total Income Tax Related Regulatory Liabilities</b>	<b>862.8</b>	<b>1,720.3</b>	
<b>Total Regulatory Liabilities Pending Final Regulatory Determination</b>	<b>863.0</b>	<b>1,720.5</b>	
<b>Regulatory liabilities approved for payment:</b>			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Asset Removal Costs	2,876.7	2,742.8	(d)
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years
Excess Earnings	8.3	8.9	34 years
Deferred Investment Tax Credits	6.2	8.7	41 years
Other Regulatory Liabilities Approved for Payment	6.1	8.9	various
<b>Total Regulatory Liabilities Currently Paying a Return</b>	<b>2,934.5</b>	<b>2,838.1</b>	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(e)
Deferred Investment Tax Credits	215.3	204.9	43 years
PJM Transmission Enhancement Refund	67.3	164.2	6 years
Transition and Restoration Charges - Texas	50.5	46.0	10 years
Spent Nuclear Fuel	43.6	42.9	(e)
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years
Deferred Gain on Sale of Rockport Unit 2	27.2	—	3 years
Peak Demand Reduction/Energy Efficiency	23.0	17.5	2 years
Unrealized Gain on Forward Commitments	17.7	45.9	5 years
Other Regulatory Liabilities Approved for Payment	70.0	73.5	various
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	<b>1,808.4</b>	<b>1,477.8</b>	
<u>Income Tax Related Regulatory Liabilities (a)</u>			

Excess ADIT Associated with Certain Depreciable Property	3,303.0	2,925.7	(f)
Excess ADIT that is Not Subject to Rate Normalization Requirements	890.5	864.3	17 years
Income Taxes Subject to Flow Through	<u>(1,341.8)</u>	<u>(1,286.1)</u>	56 years
<b>Total Income Tax Related Regulatory Liabilities</b>	<u>2,851.7</u>	<u>2,503.9</u>	
<b>Total Regulatory Liabilities Approved for Payment</b>	<u>7,594.6</u>	<u>6,819.8</u>	
<b>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>	<u>\$ 8,457.6</u>	<u>\$ 8,540.3</u>	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Includes \$275 million that will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
- (c) Includes \$71 million from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
- (d) Relieved as removal costs are incurred.
- (e) Relieved when plant is decommissioned.
- (f) Refunded using ARAM.
- (g) 2019 and 2018 amounts include approximately \$172 million related to AEP Transmission Holdco's investment in ETT and Transource Energy. AEP Transmission Holdco expects to amortize the balance commensurate with the return of Excess ADIT to ETT and Transource Energy's customers.

	AEP Texas		
	December 31,		Remaining Recovery Period
	2019	2018	
	(in millions)		
<hr/>			
Noncurrent Regulatory Assets			
<hr/>			
Regulatory assets pending final regulatory approval:			
<hr/>			
Regulatory Assets Currently Not Earning a Return			
Vegetation Management Program (a)	\$ 29.4	\$ —	
Storm-Related Costs (b)	—	152.4	
Other Regulatory Assets Pending Final Regulatory Approval	1.4	0.2	
Total Regulatory Assets Pending Final Regulatory Approval	30.8	152.6	
<hr/>			
Regulatory assets approved for recovery:			
<hr/>			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	35.2	40.1	8 years
Advanced Metering System	26.5	45.3	2 years
Total Regulatory Assets Currently Earning a Return	61.7	85.4	
<hr/>			
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	172.0	176.9	11 years
Unamortized Loss on Reacquired Debt	6.4	6.0	18 years
Other Regulatory Assets Approved for Recovery	9.7	9.1	various
Total Regulatory Assets Currently Not Earning a Return	188.1	192.0	
<hr/>			
Total Regulatory Assets Approved for Recovery	249.8	277.4	
<hr/>			
Total Noncurrent Regulatory Assets	\$ 280.6	\$ 430.0	

(a) Includes \$26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(b) In September 2019, AEP Texas securitized \$235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See “Texas Storm Cost Securitization” section of Note 4 - Rate Matters for additional information.

	AEP Texas		
	December 31,		Remaining
Regulatory Liabilities:	2019	2018	Refund
	(in millions)		Period
<hr/>			
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
<hr/>			
Regulatory liabilities pending final regulatory determination:			
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	\$ 274.9	\$ 277.1	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	87.1	141.4	(c)
<b>Total Regulatory Liabilities Pending Final Regulatory Determination</b>	<b>362.0</b>	<b>418.5</b>	
<hr/>			
Regulatory liabilities approved for payment:			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Asset Removal Costs	689.6	645.2	(d)
Excess Earnings	5.8	6.3	12 years
Advanced Metering Infrastructure Surcharge	4.3	8.5	1 year
<b>Total Regulatory Liabilities Currently Paying a Return</b>	<b>699.7</b>	<b>660.0</b>	
<hr/>			
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Transition and Restoration Charges	50.5	46.0	10 years
Deferred Investment Tax Credits	9.6	10.8	43 years
Other Regulatory Liabilities Approved for Payment	4.8	—	various
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	<b>64.9</b>	<b>56.8</b>	
<hr/>			
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	236.5	251.8	(e)
Income Taxes Subject to Flow Through	(46.2)	(42.8)	13 years
<b>Total Income Tax Related Regulatory Liabilities</b>	<b>190.3</b>	<b>209.0</b>	
<hr/>			
<b>Total Regulatory Liabilities Approved for Payment</b>	<b>954.9</b>	<b>925.8</b>	
<hr/>			
<b>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>	<b>\$ 1,316.9</b>	<b>\$ 1,344.3</b>	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
- (c) Includes \$71 million from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
- (d) Relieved as removal costs are incurred.
- (e) Refunded using ARAM.

Regulatory Assets:	AEPTCo		
	December 31,		Remaining Recovery Period
	2019	2018	
	(in millions)		
<hr/>			
Noncurrent Regulatory Assets			
<hr/>			
Regulatory assets approved for recovery:			
<u>Regulatory Assets Currently Not Earning a Return</u>			
PJM/SPP Annual Formula Rate True Up	\$ 4.2	\$ 12.9	2 years
Total Regulatory Assets Approved for Recovery	4.2	12.9	
Total Noncurrent Regulatory Assets	\$ 4.2	\$ 12.9	
<hr/>			
Regulatory Liabilities:	AEPTCo		Remaining Refund Period
	December 31,		
	2019	2018	
	(in millions)		
<hr/>			
Noncurrent Regulatory Liabilities			
<hr/>			
Regulatory liabilities pending final regulatory determination:			
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	\$ —	\$ 73.9	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	4.5	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	78.4	
Regulatory liabilities approved for payment:			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Asset Removal Costs	141.0	99.5	(b)
Total Regulatory Liabilities Currently Paying a Return	141.0	99.5	
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	535.7	453.4	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(35.4)	(28.5)	9 years
Income Taxes Subject to Flow Through	(100.4)	(81.5)	44 years
Total Income Tax Related Regulatory Liabilities	399.9	343.4	
Total Regulatory Liabilities Approved for Payment	540.9	442.9	
Total Noncurrent Regulatory Liabilities	\$ 540.9	\$ 521.3	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Relieved as removal costs are incurred.
- (c) Refunded using ARAM



	APCo		
	December 31,		Remaining
	2019	2018	Recovery
	(in millions)		Period
<hr/>			
<b>Regulatory Assets:</b>			
<hr/>			
<b>Current Regulatory Assets</b>			
<hr/>			
Under-recovered Fuel Costs, Virginia - earns a return	\$ 36.8	\$ 82.4	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	5.7	17.2	1 year
<b>Total Current Regulatory Assets</b>	<u>\$ 42.5</u>	<u>\$ 99.6</u>	
<hr/>			
<b>Noncurrent Regulatory Assets</b>			
<hr/>			
<b>Regulatory assets pending final regulatory approval:</b>			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs - Materials and Supplies	\$ 0.5	\$ 9.0	
<b>Total Regulatory Assets Currently Earning a Return</b>	<u>0.5</u>	<u>9.0</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.6	
<b>Total Regulatory Assets Currently Not Earning a Return</b>	<u>30.1</u>	<u>35.9</u>	
<hr/>			
<b>Total Regulatory Assets Pending Final Regulatory Approval (a)</b>	<u>30.6</u>	<u>44.9</u>	
<b>Regulatory assets approved for recovery:</b>			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs - Unrecovered Plant - West Virginia	86.4	85.3	24 years
Other Regulatory Assets Approved for Recovery	0.5	1.2	various
<b>Total Regulatory Assets Currently Earning a Return</b>	<u>86.9</u>	<u>86.5</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Pension and OPEB Funded Status	160.8	172.2	11 years
Unamortized Loss on Reacquired Debt	85.5	89.3	23 years
Vegetation Management Program - West Virginia	43.6	26.6	2 years
Peak Demand Reduction/Energy Efficiency	19.5	19.7	7 years
Postemployment Benefits	15.9	18.0	4 years
Virginia Generation Rate Adjustment Clause	5.1	10.3	2 years
Other Regulatory Assets Approved for Recovery	9.3	8.3	various
<b>Total Regulatory Assets Currently Not Earning a Return</b>	<u>339.7</u>	<u>344.4</u>	
<hr/>			
<b>Total Regulatory Assets Approved for Recovery</b>	<u>426.6</u>	<u>430.9</u>	
<hr/>			
<b>Total Noncurrent Regulatory Assets</b>	\$ 457.2	\$ 475.8	

(a) In 2015, APCo recorded a \$91 million reduction, before cost of removal which was \$11 million and \$20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo's Virginia jurisdiction. The net book value of these plants at the retirement date was \$93 million before cost of removal, including

materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of \$93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately \$51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

	APCo		
	December 31,		Remaining Refund Period
	2019	2018	
	(in millions)		
<b>Regulatory Liabilities:</b>			
<b>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>			
<b>Regulatory liabilities pending final regulatory determination:</b>			
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	\$ —	\$ 268.2	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	283.7	
<b>Total Regulatory Liabilities Pending Final Regulatory Determination</b>	—	551.9	
<b>Regulatory liabilities approved for payment:</b>			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Asset Removal Costs	635.3	618.3	(b)
Deferred Investment Tax Credits	0.5	1.0	41 years
<b>Total Regulatory Liabilities Currently Paying a Return</b>	635.8	619.3	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years
PJM Transmission Enhancement Refund	19.5	47.7	6 years
Unrealized Gain on Forward Commitments	9.3	34.7	5 years
Consumer Rate Relief - West Virginia	5.4	8.8	1 year
Other Regulatory Liabilities Approved for Payment	3.3	3.9	various
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	65.6	106.4	
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	718.9	453.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	210.7	84.5	9 years
Income Taxes Subject to Flow Through	(362.3)	(365.9)	23 years
<b>Total Income Tax Related Regulatory Liabilities</b>	567.3	172.1	
<b>Total Regulatory Liabilities Approved for Payment</b>	1,268.7	897.8	
<b>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>	\$ 1,268.7	\$ 1,449.7	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Relieved as removal costs are incurred.
- (c) Refunded using ARAM.

Regulatory Assets:	I&M		Remaining Recovery Period
	December 31,		
	2019	2018	
(in millions)			
<b>Current Regulatory Assets</b>			
Under-recovered Fuel Costs - earns a return	\$ 3.0	\$ —	1 Year
<b>Total Current Regulatory Assets</b>	<u>\$ 3.0</u>	<u>\$ —</u>	
<b>Noncurrent Regulatory Assets</b>			
<b>Regulatory assets pending final regulatory approval:</b>			
<u>Regulatory Assets Currently Not Earning a Return</u>			
Cook Plant Study Costs	\$ 7.6	\$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	3.3	
<b>Total Regulatory Assets Pending Final Regulatory Approval</b>	<u>7.7</u>	<u>3.3</u>	
<b>Regulatory assets approved for recovery:</b>			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs - Unrecovered Plant	214.9	232.2	9 years
Cook Plant Uprate Project	32.6	35.0	14 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years
Rockport Plant Dry Sorbent Injection System - Indiana	10.2	11.5	8 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.4	5.7	19 years
Other Regulatory Assets Approved for Recovery	4.8	2.4	various
<b>Total Regulatory Assets Currently Earning a Return</b>	<u>296.4</u>	<u>318.7</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Pension and OPEB Funded Status	67.5	84.9	11 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Unamortized Loss on Reacquired Debt	17.2	18.7	29 years
Postemployment Benefits	7.2	6.5	4 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	22.3	22.8	various
<b>Total Regulatory Assets Currently Not Earning a Return</b>	<u>178.0</u>	<u>190.5</u>	
<b>Total Regulatory Assets Approved for Recovery</b>	<u>474.4</u>	<u>509.2</u>	
<b>Total Noncurrent Regulatory Assets</b>	\$ 482.1	\$ 512.5	

	I&M		
	December 31,		Remaining
Regulatory Liabilities:	2019	2018	Refund
	(in millions)		Period
<b>Current Regulatory Liabilities</b>			
Over-recovered Fuel Costs, Michigan - pays a return	\$ —	\$ 4.5	
Over-recovered Fuel Costs, Indiana - does not pay a return	6.1	22.9	1 year
<b>Total Current Regulatory Liabilities</b>	<b>\$ 6.1</b>	<b>\$ 27.4</b>	
<b>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>			
<b>Regulatory liabilities pending final regulatory determination:</b>			
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	\$ —	\$ 125.0	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	40.6	
<b>Total Regulatory Liabilities Pending Final Regulatory Determination</b>	<b>—</b>	<b>165.6</b>	
<b>Regulatory liabilities approved for payment:</b>			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Asset Removal Costs	166.7	182.5	(b)
Other Regulatory Liabilities Approved for Payment	0.3	—	various
<b>Total Regulatory Liabilities Currently Paying a Return</b>	<b>167.0</b>	<b>182.5</b>	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(c)
Spent Nuclear Fuel	43.6	42.9	(c)
Deferred Investment Tax Credits	25.8	29.4	20 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	17.0	—	2 years
PJM Transmission Enhancement Refund	11.8	29.1	6 years
Deferred Gain on Sale of Rockport Unit 2	10.9	—	3 years
Other Regulatory Liabilities Approved for Payment	24.9	24.0	various
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	<b>1,370.0</b>	<b>953.9</b>	
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	470.9	362.0	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	184.5	192.6	5 years
Income Taxes Subject to Flow Through	(301.0)	(282.1)	19 years
<b>Total Income Tax Related Regulatory Liabilities</b>	<b>354.4</b>	<b>272.5</b>	
<b>Total Regulatory Liabilities Approved for Payment</b>	<b>1,891.4</b>	<b>1,408.9</b>	
<b>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>	<b>\$ 1,891.4</b>	<b>\$ 1,574.5</b>	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Relieved as removal costs are incurred.
- (c) Relieved when plant is decommissioned.
- (d) Refunded using ARAM.

Regulatory Assets:	OPCo		
	December 31,		Remaining Recovery Period
	2019	2018	
	(in millions)		
<b>Current Regulatory Assets</b>			
Under-recovered Fuel Costs - earns a return	\$ —	\$ 0.4	
<b>Total Current Regulatory Assets</b>	<u>\$ —</u>	<u>\$ 0.4</u>	
<b>Noncurrent Regulatory Assets</b>			
<b>Regulatory assets pending final regulatory approval:</b>			
<u>Regulatory Assets Currently Not Earning a Return</u>			
Other Regulatory Assets Pending Final Regulatory Approval	\$ 0.1	\$ 1.0	
<b>Total Regulatory Assets Pending Final Regulatory Approval</b>	<u>0.1</u>	<u>1.0</u>	
<b>Regulatory assets approved for recovery:</b>			
<u>Regulatory Assets Currently Earning a Return</u>			
Ohio Distribution Decoupling	31.4	12.3	2 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	—	0.9	
<b>Total Regulatory Assets Currently Earning a Return</b>	<u>31.4</u>	<u>71.0</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Pension and OPEB Funded Status	167.3	181.5	11 years
Unrealized Loss on Forward Commitments	103.6	100.2	13 years
Smart Grid Costs	13.7	8.1	2 years
Distribution Investment Rider	10.9	—	2 years
Postemployment Benefits	7.6	7.9	4 years
Unamortized Loss on Reacquired Debt	5.3	6.5	19 years
Other Regulatory Assets Approved for Recovery	11.9	11.3	various
<b>Total Regulatory Assets Currently Not Earning a Return</b>	<u>320.3</u>	<u>315.5</u>	
<b>Total Regulatory Assets Approved for Recovery</b>	<u>351.7</u>	<u>386.5</u>	
<b>Total Noncurrent Regulatory Assets</b>	<u>\$ 351.8</u>	<u>\$ 387.5</u>	

	OPCo		
	December 31,		Remaining
	2019	2018	Refund
	(in millions)		Period
Regulatory Liabilities:			
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	\$ 2.8	\$ —	1 year
Total Current Regulatory Liabilities	\$ 2.8	\$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	\$ 0.2	\$ 0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	446.3	436.6	(b)
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years
Other Regulatory Liabilities Approved for Payment	1.3	0.4	various
Total Regulatory Liabilities Currently Paying a Return	484.8	505.8	
Regulatory Liabilities Currently Not Paying a Return			
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
PJM Transmission Enhancement Refund	29.4	71.3	6 years
Peak Demand Reduction/Energy Efficiency	19.7	14.9	2 years
Distribution Investment Rider	—	7.8	
Other Regulatory Liabilities Approved for Payment	2.9	11.3	various
Total Regulatory Liabilities Currently Not Paying a Return	81.7	148.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	341.6	350.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	252.3	279.1	9 years
Income Taxes Subject to Flow Through	(69.7)	(62.8)	28 years
Total Income Tax Related Regulatory Liabilities	524.2	566.8	
Total Regulatory Liabilities Approved for Payment	1,090.7	1,221.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	\$ 1,090.9	\$ 1,221.2	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Relieved as removal costs are incurred.

(c)     Refunded using ARAM

205

---

	PSO		
	December 31,		Remaining
	2019	2018	Recovery
	(in millions)		Period
Regulatory Assets:			
<hr/>			
Noncurrent Regulatory Assets			
<hr/>			
Regulatory assets pending final regulatory approval:			
<hr/>			
Regulatory Assets Currently Earning a Return			
Oklunion Power Station Accelerated Depreciation	\$ 27.4	\$ 5.5	
Total Regulatory Assets Currently Earning a Return	27.4	5.5	
<hr/>			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	7.2	—	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.5	
Total Regulatory Assets Currently Not Earning a Return	7.2	0.5	
<hr/>			
Total Regulatory Assets Pending Final Regulatory Approval	34.6	6.0	
<hr/>			
Regulatory assets approved for recovery:			
<hr/>			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	167.0	153.4	21 years
Meter Replacement Costs	30.2	34.3	8 years
Environmental Control Projects	27.8	29.2	21 years
Storm-Related Costs	21.3	31.1	3 years
Red Rock Generating Facility	8.4	8.6	37 years
Other Regulatory Assets Approved for Recovery	0.6	0.5	various
Total Regulatory Assets Currently Earning a Return	255.3	257.1	
<hr/>			
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	73.4	84.3	11 years
Unamortized Loss on Reacquired Debt	6.5	4.3	15 years
Peak Demand Reduction/Energy Efficiency	—	6.3	
Other Regulatory Assets Approved for Recovery	5.4	11.0	various
Total Regulatory Assets Currently Not Earning a Return	85.3	105.9	
<hr/>			
Total Regulatory Assets Approved for Recovery	340.6	363.0	
<hr/>			
Total Noncurrent Regulatory Assets	\$ 375.2	\$ 369.0	

	PSO		
	December 31,		Remaining
	2019	2018	Refund
	(in millions)		Period
Regulatory Liabilities:			
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	\$ 63.9	\$ 20.1	1 year
Total Current Regulatory Liabilities	\$ 63.9	\$ 20.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	\$ 286.8	\$ 276.8	(b)
Total Regulatory Liabilities Currently Paying a Return	286.8	276.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.5	51.5	25 years
Other Regulatory Liabilities Approved for Payment	4.7	2.5	various
Total Regulatory Liabilities Currently Not Paying a Return	56.2	54.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	405.8	415.2	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	96.3	126.4	5 years
Income Taxes Subject to Flow Through	(7.9)	(7.7)	24 years
Total Income Tax Related Regulatory Liabilities	494.2	533.9	
Total Regulatory Liabilities Approved for Payment	837.2	864.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	\$ 837.2	\$ 864.7	

- (a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (b) Relieved as removal costs are incurred.
- (c) Refunded using ARAM.

	SWEPCo		
	December 31,		Remaining Recovery Period
	2019	2018	
Regulatory Assets:	(in millions)		
<hr/>			
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	\$ 4.9	\$ 18.8	1 year
Total Current Regulatory Assets	<u>\$ 4.9</u>	<u>\$ 18.8</u>	
<hr/>			
Noncurrent Regulatory Assets			
<hr/>			
Regulatory assets pending final regulatory approval:			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs - Unrecovered Plant, Louisiana	\$ 35.2	\$ 50.3	
Other Regulatory Assets Pending Final Regulatory Approval	0.2	0.3	
Total Regulatory Assets Currently Earning a Return	<u>35.4</u>	<u>50.6</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Asset Retirement Obligation - Louisiana	7.2	5.3	
Rate Case Expense - Texas	1.0	4.9	
Other Regulatory Assets Pending Final Regulatory Approval	2.7	3.6	
Total Regulatory Assets Currently Not Earning a Return	<u>10.9</u>	<u>13.8</u>	
<hr/>			
Total Regulatory Assets Pending Final Regulatory Approval	<u>46.3</u>	<u>64.4</u>	
Regulatory assets approved for recovery:			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs - Unrecovered Plant, Arkansas	15.1	—	23 years
Environmental Controls Projects	13.2	14.2	13 years
Other Regulatory Assets Approved for Recovery	8.9	7.2	various
Total Regulatory Assets Currently Earning a Return	<u>37.2</u>	<u>21.4</u>	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Pension and OPEB Funded Status	102.6	108.4	11 years
Plant Retirement Costs - Unrecovered Plant, Texas	16.6	17.1	22 years
Unamortized Loss on Reacquired Debt	6.6	7.4	24 years
Rate Case Expense - Arkansas	5.2	0.8	5 years
Other Regulatory Assets Approved for Recovery	7.9	11.3	various
Total Regulatory Assets Currently Not Earning a Return	<u>138.9</u>	<u>145.0</u>	
<hr/>			
Total Regulatory Assets Approved for Recovery	<u>176.1</u>	<u>166.4</u>	
<hr/>			
Total Noncurrent Regulatory Assets	\$ 222.4	\$ 230.8	

(a) December 31, 2019 amount includes Arkansas jurisdiction. December 31, 2018 amount includes Arkansas and Louisiana jurisdictions.

SWEPCo			
	December 31,		Remaining Refund Period
	2019	2018	
(in millions)			
Regulatory Liabilities:			
<b>Current Regulatory Liabilities</b>			
Over-recovered Fuel Costs - pays a return (a)	\$ 13.6	\$ 11.1	1 year
<b>Total Current Regulatory Liabilities</b>	<b>\$ 13.6</b>	<b>\$ 11.1</b>	
<b>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>			
<b>Regulatory liabilities pending final regulatory determination:</b>			
<b>Income Tax Related Regulatory Liabilities (b)</b>			
Excess ADIT Associated with Certain Depreciable Property	\$ 297.0	\$ 280.1	
Excess ADIT that is Not Subject to Rate Normalization Requirements	22.7	26.9	
<b>Total Regulatory Liabilities Pending Final Regulatory Determination</b>	<b>319.7</b>	<b>307.0</b>	
<b>Regulatory liabilities approved for payment:</b>			
<b>Regulatory Liabilities Currently Paying a Return</b>			
Asset Removal Costs	453.4	437.8	(c)
Other Regulatory Liabilities Approved for Payment	2.8	2.5	various
<b>Total Regulatory Liabilities Currently Paying a Return</b>	<b>456.2</b>	<b>440.3</b>	
<b>Regulatory Liabilities Currently Not Paying a Return</b>			
Peak Demand Reduction/Energy Efficiency	6.0	2.5	2 years
Deferred Investment Tax Credits	3.1	4.5	12 years
Other Regulatory Liabilities Approved for Payment	1.7	2.4	various
<b>Total Regulatory Liabilities Currently Not Paying a Return</b>	<b>10.8</b>	<b>9.4</b>	
<b>Income Tax Related Regulatory Liabilities (b)</b>			
Excess ADIT Associated with Certain Depreciable Property	339.4	370.5	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	27.8	54.3	1 year
Income Taxes Subject to Flow Through	(261.6)	(258.5)	28 years
<b>Total Income Tax Related Regulatory Liabilities</b>	<b>105.6</b>	<b>166.3</b>	
<b>Total Regulatory Liabilities Approved for Payment</b>	<b>572.6</b>	<b>616.0</b>	
<b>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</b>	<b>\$ 892.3</b>	<b>\$ 923.0</b>	

- (a) December 31, 2019 amount includes Texas and Louisiana jurisdictions. December 31, 2018 amount includes Texas jurisdiction.
- (b) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
- (c) Relieved as removal costs are incurred.
- (d) Refunded using ARAM.



## 6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

### COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2019:

<b>Contractual Commitments - AEP</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Fuel Purchase Contracts (a)	\$ 1,047.0	\$ 1,105.0	\$ 234.4	\$ 111.4	\$ 2,497.8
Energy and Capacity Purchase Contracts	227.8	353.2	273.5	1,080.0	1,934.5
<b>Total</b>	<b>\$ 1,274.8</b>	<b>\$ 1,458.2</b>	<b>\$ 507.9</b>	<b>\$ 1,191.4</b>	<b>\$ 4,432.3</b>

<b>Contractual Commitments - APCo</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Fuel Purchase Contracts (a)	\$ 415.3	\$ 369.2	\$ 4.6	\$ 0.3	\$ 789.4
Energy and Capacity Purchase Contracts	35.4	72.1	73.7	275.5	456.7
<b>Total</b>	<b>\$ 450.7</b>	<b>\$ 441.3</b>	<b>\$ 78.3</b>	<b>\$ 275.8</b>	<b>\$ 1,246.1</b>

<b>Contractual Commitments - I&amp;M</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Fuel Purchase Contracts (a)	\$ 299.8	\$ 340.7	\$ 211.6	\$ 67.2	\$ 919.3
Energy and Capacity Purchase Contracts	151.0	340.5	60.4	289.2	841.1
<b>Total</b>	<b>\$ 450.8</b>	<b>\$ 681.2</b>	<b>\$ 272.0</b>	<b>\$ 356.4</b>	<b>\$ 1,760.4</b>

<b>Contractual Commitments - OPCo</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Energy and Capacity Purchase Contracts	\$ 29.0	\$ 58.6	\$ 58.8	\$ 302.5	\$ 448.9

<b>Contractual Commitments - PSO</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Fuel Purchase Contracts (a)	\$ 52.3	\$ 42.8	\$ —	\$ —	\$ 95.1
Energy and Capacity Purchase Contracts	93.0	132.3	65.2	193.3	483.8
<b>Total</b>	<b>\$ 145.3</b>	<b>\$ 175.1</b>	<b>\$ 65.2</b>	<b>\$ 193.3</b>	<b>\$ 578.9</b>

<b>Contractual Commitments - SWEPCo</b>	<b>Less Than 1 Year</b>	<b>2-3 Years</b>	<b>4-5 Years</b>	<b>After 5 Years</b>	<b>Total</b>
	<b>(in millions)</b>				
Fuel Purchase Contracts (a)	\$ 130.4	\$ 147.4	\$ 4.5	\$ —	\$ 282.3
Energy and Capacity Purchase Contracts	14.0	12.5	8.4	8.4	43.3
<b>Total</b>	<b>\$ 144.4</b>	<b>\$ 159.9</b>	<b>\$ 12.9</b>	<b>\$ 8.4</b>	<b>\$ 325.6</b>

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

## **GUARANTEES**

Liabilities for guarantees are recorded in accordance with the accounting guidance for “Guarantees.” There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

### ***Letters of Credit (Applies to AEP, AEP Texas and OPCo)***

Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has a \$4 billion revolving credit facility due in June 2022, under which up to \$1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2019, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling \$405 million. The Registrants’ maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2019 were as follows:

<b>Company</b>	<b>Amount</b>	<b>Maturity</b>
	<b>(in millions)</b>	
AEP	\$ 206.8	January 2020 to December 2020
AEP Texas	2.2	July 2020
OPCo	1.6	April 2020 to September 2020

### ***Guarantees of Equity Method Investees (Applies to AEP)***

In April 2019, AEP acquired Sempra Renewables LLC. See “Acquisitions” section of Note 7 for additional information.

### ***Indemnifications and Other Guarantees***

*Contracts*

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2019, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase and sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

#### *Lease Obligations*

Certain Registrants lease equipment under master lease agreements. See “Master Lease Agreements” and “AEPRO Boat and Barge Leases” sections of Note 13 for additional information.

### **ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)**

#### ***The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation***

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2019, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, three, and one sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at three sites under state law. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2019, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

### **NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)**

I&M owns and operates the two-unit 2,288 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

#### ***Decommissioning and Low-Level Waste Accumulation Disposal***

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was \$2 billion in 2018 non-discounted dollars, with additional ongoing costs of \$6 million per year for post decommissioning storage of SNF and an eventual cost of \$37 million for the subsequent



decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were \$7 million, \$8 million and \$9 million for the years ended December 31, 2019, 2018 and 2017, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2019 and 2018, the total decommissioning trust fund balances were \$2.7 billion and \$2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

### ***Spent Nuclear Fuel Disposal***

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to \$0. As of December 31, 2019 and 2018, fees and related interest of \$280 million and \$274 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling \$323 million and \$317 million, respectively, to pay the fee were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received \$8 million, \$11 million and \$22 million in 2019, 2018 and 2017, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December 31, 2019 and 2018, I&M deferred \$24 million and \$8 million, respectively, in Prepayments and Other Current Assets and \$1 million and \$23 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for additional information.

### ***Nuclear Insurance***

I&M carries nuclear property insurance of \$2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at Cook Plant is \$1 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to \$47 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of \$13.9 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides \$450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of \$275 million per nuclear incident on Cook Plant's reactors payable in annual installments of \$41 million. The number of incidents for which payments could be required is not limited.



In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first \$450 million through commercially available insurance. The next level of liability coverage of up to \$13.5 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

## **OPERATIONAL CONTINGENCIES**

### ***Insurance and Potential Losses***

The Registrants maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. The Registrants also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by the Registrants. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers. See “Nuclear Contingencies” section above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

### ***Rockport Plant Litigation (Applies to AEP and I&M)***

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal by the U.S. District Court for the Southern District of Ohio of certain of the plaintiffs’ claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

In 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court’s dismissal of the owners’ breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court’s dismissal of the breach of contract claims and remanding the case for further proceedings.

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners’ unopposed motion to stay the lease litigation to afford time for resolution of AEP’s motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional \$7.5 million to citizens’ groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the \$7.5 million payment was shared between AEGCo and I&M based on the



joint ownership agreement. The district court entered a stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. See “Modification of the New Source Review Litigation Consent Decree” section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs’ claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management cannot determine a range of potential losses that is reasonably possible of occurring.

### ***Patent Infringement Complaint***

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

### ***Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula***

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan’s benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant’s career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

## 7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

The disclosures in this note apply to AEP unless indicated otherwise.

### ACQUISITIONS

#### 2019

##### *Sempra Renewables LLC (Generation & Marketing Segment)*

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately \$1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid \$580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at \$404 million as of the acquisition date (which includes \$364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of \$135 million. The purchase price was allocated as follows:

#### **Purchase Price Allocation of Sempra Renewables LLC at Acquisition Date - April 22nd, 2019**

<b>Assets:</b>		<b>Liabilities and Equity:</b>		<b>Net Purchase Price</b>
		(in millions)		
Current Assets	\$ 8.8	Current Liabilities	\$ 12.9	
Property, Plant and Equipment	238.1	Asset Retirement Obligations	5.7	
Investment in Joint Ventures	404.0	<b>Total Liabilities</b>	<b>18.6</b>	
Other Noncurrent Assets	82.9	Noncontrolling Interest	134.8	
<b>Total Assets</b>	<b>\$ 733.8</b>	<b>Liabilities and Noncontrolling Interest</b>	<b>\$ 153.4</b>	<b>\$ 580.4</b>

Management allocated the purchase price based upon the relative fair value of the assets acquired and noncontrolling interests assumed. The fair value of the primary assets acquired and the noncontrolling interests assumed was determined using a discounted cash flow method under the income approach. The key input assumptions utilized in the determination of the fair value of these assets were the pricing and terms of the existing PPAs, forecasted market power prices, expected wind farm net capacity and discount rates reflecting risk inherent in the future cash flows and future power prices. Estimating forecasted market power prices involved determining the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third-party market participant assumptions. The expected wind farm net capacity was developed by evaluating each wind farm's historical and expected generation against historical generation of comparable wind farms in the same locations. Discount rates were evaluated by considering the cost of capital of comparable businesses. Additional key input assumptions for the fair value of the noncontrolling interests include the terms of the limited liability company agreements that dictate the sharing of the tax attributes and cash flows associated with the tax equity partnerships. Under the accounting rules for acquisitions, AEP has one year to finalize the purchase price allocation, including working capital adjustments and other closing adjustments.

Upon closing of the purchase, Sempra Renewables LLC was legally renamed AEP Wind Holdings LLC. AEP Wind Holdings LLC develops, owns and operates, or holds interests in, wind generation facilities in the United States. The operating wind generation portfolio includes seven wind farms. Five wind farms are jointly-owned with BP Wind Energy, and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. All seven wind farms have long-term PPAs for 100% of their energy production. One of the joint venture wind farms has PPAs with I&M and OPCo for a portion of its energy production which totaled \$9 million and \$17 million, respectively, for the year ended December 31, 2019. Another joint venture wind farm has a PPA with SWEPCo for a portion of its energy production which totaled \$10 million of purchased electricity for the year ended December 31, 2019. The PPAs with I&M, OPCo and SWEPCo were executed prior to the acquisition of the wind farms and will be accounted for in accordance with the accounting guidance for "Related Parties."



Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of December 31, 2019, the maximum potential amount of future payments associated with these guarantees was \$175 million, with the last guarantee expiring in December 2037. The liability recorded associated with these guarantees was \$34 million as of December 31, 2019.

The acquired business contributed revenues and net income to AEP that were not material for the period April 22, 2019 to December 31, 2019. The pro-forma revenue and net income related to the acquisition of Semptra Renewables LLC were not material for the year ended December 31, 2019.

See Note 17 - Variable Interest Entities and Equity Method Investments for additional information related to the purchased wind farms.

### ***Santa Rita East (Generation & Marketing Segment)***

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately \$356 million. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Santa Rita East represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Santa Rita East is a VIE. As a result, to account for the initial consolidation of Santa Rita East, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP's interest in Santa Rita East and recent third-party market transactions for similar wind farms. See "Santa Rita East" section of Note 17 for additional information.

## **DISPOSITIONS**

### **2017**

#### ***Zimmer Plant (Generation & Marketing Segment)***

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the years ended December 31, 2017 and 2016.

#### ***Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)***

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for \$2.2 billion, which was recorded in Investing Activities on the statements of cash flows. The net proceeds from the transaction were \$1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of \$226 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statements of income for the year ended December 31, 2017.

## **IMPAIRMENTS**

### **2019**

#### ***2019 Texas Base Rate Case (Transmission and Distribution Segment) (Applies to AEP and AEP Texas)***

In December 2019, AEP Texas recorded a pretax impairment of \$33 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowances in the 2019 Texas Base Rate Case. See “2019 Texas Base Rate Case” section of Note 4 for additional information.

#### ***Virginia Jurisdictional Book Value of Retired Coal-Fired Plants (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)***

In December 2019, based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of \$93 million related to its previously retired coal-fired generation. This expense is recorded in Asset Impairments and Other Related Charges on the statements of income. See “Virginia Legislation Affecting Earnings Reviews” section of Note 4 for additional information.

#### ***Merchant Generating Assets (Generation & Marketing Segment)***

Due to a significant increase in the asset retirement costs recorded in December 2019 for the Ash Pond Complex at Conesville Plant, AEP performed an impairment analysis on Conesville Plant in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one and step two of the impairment analysis using a cash flow model for the estimated useful life of Conesville Plant based upon energy and capacity price curves, which were developed internally with both observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management’s forecasts of operating expenses. The step two analysis resulted in a fair value determination for Conesville Plant of \$0 and AEP recorded a \$31 million pretax impairment, equal to the net book value of the plant, in Asset Impairments and Other Related Charges on AEP’s statements of income in the fourth quarter of 2019.

### **2018**

#### ***Other Assets (Corporate and Other) (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)***

In the first quarter of 2018, AEP was notified by an equity investee that it had ceased operations. AEP recorded a pretax impairment of \$21 million in Asset Impairments and Other Related Charges on the statements of income related to the equity investment and related assets. The impairment also had an immaterial impact to APCo.

#### ***Merchant Generating Assets (Generation & Marketing Segment)***

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017 and reconstruction activities continued throughout 2018. An initial impairment recorded related to Racine is discussed in the “2017” section below.

As of September 30, 2018, the Racine reconstruction project had accumulated new capital expenditures of \$35 million. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management’s forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a determination that the fair value of Racine in its condition as of September 30, 2018 was \$0. As a result, AEP recorded a pretax impairment of \$35 million in Other Operation on the statements of income in the third quarter of 2018. In October 2018, AEP received authorization from the FERC to restart generation at Racine and generation resumed in November 2018.



Reconstruction activities at Racine are currently estimated to be completed in the first half of 2020. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the book value once complete. Future revisions in cost estimates or delays in completion could result in additional losses which could reduce future net income and cash flows and impact financial condition.

## **2017**

### ***Merchant Generating Assets (Generation & Marketing Segment)***

In 2017, AEP recorded an additional pretax impairment of \$4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets"). In addition, AEP recorded a \$7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

Due to a significant increase in estimated costs identified in December 2017 to repair a defective dam structure at Racine, AEP performed an impairment analysis on Racine in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with both observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a fair value determination for Racine of \$0 and AEP recorded a pretax impairment of \$43 million in Assets Impairments and Other Related Charges on the statements of income in the fourth quarter of 2017.

### ***Welsh Plant, Unit 2 and Turk Plant (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)***

In December 2017, SWEPCo recorded a pretax impairment of \$19 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional share of Welsh Plant, Unit 2 and other disallowed plant investments. Additionally in December 2017, SWEPCo recorded a pretax impairment of \$15 million in Asset Impairments and Other Related Charges on the statements of income related to the Louisiana jurisdictional share of the Turk Plant. See the "2016 Texas Base Rate Case" section of Note 4.

## 8. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Fair Value Measurements of Assets and Liabilities” and “Investments Held in Trust for Future Liabilities” sections of Note 1.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries’ participation in AEP’s benefit plans, the assumptions used by the actuary, with the exception of the rate of compensation increase, and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the “Compensation – Retirement Benefits” accounting guidance. The Registrants recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

### *Actuarial Assumptions for Benefit Obligations*

The weighted-average assumptions used in the measurement of the Registrants’ benefit obligations are shown in the following tables:

	Pension Plans		OPEB	
	December 31,			
Assumption	2019	2018	2019	2018
Discount Rate	3.25%	4.30%	3.30%	4.30%
Interest Crediting Rate	4.00%	4.00%	NA	NA

NA Not applicable.

Assumption – Rate of Compensation Increase (a)	Pension Plans	
	December 31,	
	2019	2018
AEP	4.95%	4.85%
AEP Texas	5.00%	4.95%
APCo	4.80%	4.75%
I&M	4.95%	4.90%
OPCo	5.15%	5.00%
PSO	5.05%	4.90%
SWEPCo	4.90%	4.85%

- (a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2019, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

**Actuarial Assumptions for Net Periodic Benefit Costs**

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

Assumption	Pension Plans			OPEB		
	Year Ended December 31,					
	2019	2018	2017	2019	2018	2017
Discount Rate	4.30%	3.65%	4.05%	4.30%	3.60%	4.10%
Interest Crediting Rate	4.00%	4.00%	4.00%	NA	NA	NA
Expected Return on Plan Assets	6.25%	6.00%	6.00%	6.25%	6.00%	6.75%

NA Not applicable.

Assumption – Rate of Compensation Increase (a)	Pension Plans		
	Year Ended December 31,		
	2019	2018	2017
AEP	4.95%	4.85%	4.80%
AEP Texas	5.00%	4.95%	4.90%
APCo	4.75%	4.75%	4.60%
I&M	4.95%	4.90%	4.85%
OPCo	5.20%	5.00%	4.95%
PSO	5.05%	4.90%	4.90%
SWEPCo	4.90%	4.85%	4.80%

- (a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31,	
	2019	2018
Initial	6.00%	6.25%
Ultimate	4.50%	5.00%
Year Ultimate Reached	2026	2024



### ***Significant Concentrations of Risk within Plan Assets***

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2019, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

### ***Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets***

For the year ended December 31, 2019, the pension plans had an actuarial loss due to a decrease in the discount rate, partially offset by updates to the mortality table. For the year ended December 31, 2019, the OPEB plans had an actuarial loss due to a decrease in the discount rate and an update to the persistency assumption, partially offset by an update to the projected per capita cost assumption as well as savings resulting from legislation signed in December 2019 which eliminated two Affordable Care Act taxes. For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Change in Benefit Obligation</b>	<b>(in millions)</b>			
Benefit Obligation as of January 1,	\$ 4,810.3	\$ 5,215.8	\$ 1,194.5	\$ 1,332.0
Service Cost	95.5	97.6	9.5	11.6
Interest Cost	204.4	187.8	50.5	47.4
Actuarial (Gain) Loss	493.6	(306.3)	58.8	(100.1)
Plan Amendments	0.2	—	(11.0)	—
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
Participant Contributions	—	—	35.5	36.5
Medicare Subsidy	—	—	0.6	0.7
<b>Benefit Obligation as of December 31,</b>	<b>\$ 5,236.8</b>	<b>\$ 4,810.3</b>	<b>\$ 1,225.4</b>	<b>\$ 1,194.5</b>
<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 4,695.9	\$ 5,174.1	\$ 1,534.2	\$ 1,732.5
Actual Gain (Loss) on Plan Assets	681.1	(104.9)	321.0	(118.3)
Company Contributions (a)	5.6	11.3	4.1	17.1
Participant Contributions	—	—	35.5	36.5
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 5,015.4</b>	<b>\$ 4,695.9</b>	<b>\$ 1,781.8</b>	<b>\$ 1,534.2</b>
<b>Funded (Underfunded) Status as of December 31,</b>	<b>\$ (221.4)</b>	<b>\$ (114.4)</b>	<b>\$ 556.4</b>	<b>\$ 339.7</b>

- (a) AEP did not make contributions to the qualified pension plan in 2019 or 2018. Contributions to the nonqualified pension plans were \$6 million and \$11 million for the years ended December 31, 2019 and 2018, respectively.

<u>AEP</u>	<u>Pension Plans</u>		<u>OPEB</u>	
	<u>December 31,</u>			
	<u>2019</u>	<u>2018</u>	<u>2019</u>	<u>2018</u>
	<u>(in millions)</u>			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	\$ —	\$ —	\$ 590.8	\$ 392.2
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.1)	(5.7)	(2.6)	(2.8)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(215.3)	(108.7)	(31.8)	(49.7)
<b>Funded (Underfunded) Status</b>	<b>\$ (221.4)</b>	<b>\$ (114.4)</b>	<b>\$ 556.4</b>	<b>\$ 339.7</b>

<u>AEP Texas</u>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>(in millions)</b>			
<b>Change in Benefit Obligation</b>				
Benefit Obligation as of January 1,	\$ 409.3	\$ 441.3	\$ 95.9	\$ 107.1
Service Cost	8.6	9.2	0.8	0.9
Interest Cost	17.5	16.0	4.0	3.8
Actuarial (Gain) Loss	40.1	(20.9)	3.9	(8.3)
Plan Amendments	—	—	(0.9)	—
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
Participant Contributions	—	—	2.9	3.1
<b>Benefit Obligation as of December 31,</b>	<b>\$ 441.2</b>	<b>\$ 409.3</b>	<b>\$ 97.8</b>	<b>\$ 95.9</b>

<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 410.7	\$ 455.9	\$ 129.9	\$ 147.3
Actual Gain (Loss) on Plan Assets	58.3	(9.3)	24.0	(14.6)
Company Contributions	0.4	0.4	0.1	4.8
Participant Contributions	—	—	2.9	3.1
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 435.1</b>	<b>\$ 410.7</b>	<b>\$ 148.1</b>	<b>\$ 129.9</b>
<b>Funded (Underfunded) Status as of December 31,</b>	<b>\$ (6.1)</b>	<b>\$ 1.4</b>	<b>\$ 50.3</b>	<b>\$ 34.0</b>

	<u>Pension Plans</u>		<u>OPEB</u>	
	<u>December 31,</u>			
<u>AEP Texas</u>	<u>2019</u>	<u>2018</u>	<u>2019</u>	<u>2018</u>
	<u>(in millions)</u>			
Deferred Charges and Other Noncurrent Assets – Prepaid				
Benefit Costs	\$ —	\$ 5.2	\$ 50.3	\$ 34.0

Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(5.7)	(3.4)	—	—
<b>Funded (Underfunded) Status</b>	<u>\$ (6.1)</u>	<u>\$ 1.4</u>	<u>\$ 50.3</u>	<u>\$ 34.0</u>

**APCo**

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Change in Benefit Obligation</b>	<b>(in millions)</b>			
Benefit Obligation as of January 1,	\$ 603.1	\$ 665.0	\$ 205.5	\$ 236.5
Service Cost	9.4	9.3	1.0	1.1
Interest Cost	25.2	23.5	8.7	8.2
Actuarial (Gain) Loss	52.9	(49.2)	4.7	(21.9)
Plan Amendments	—	—	(1.7)	—
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
Participant Contributions	—	—	5.9	6.1
Medicare Subsidy	—	—	0.2	0.2
<b>Benefit Obligation as of December 31,</b>	<b>\$ 647.2</b>	<b>\$ 603.1</b>	<b>\$ 203.5</b>	<b>\$ 205.5</b>
<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 593.3	\$ 651.7	\$ 238.4	\$ 273.4
Actual Gain (Loss) on Plan Assets	87.1	(12.9)	45.3	(18.7)
Company Contributions	—	—	2.2	2.3
Participant Contributions	—	—	5.9	6.1
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 637.0</b>	<b>\$ 593.3</b>	<b>\$ 271.0</b>	<b>\$ 238.4</b>
<b>Funded (Underfunded) Status as of December 31,</b>	<b>\$ (10.2)</b>	<b>\$ (9.8)</b>	<b>\$ 67.5</b>	<b>\$ 32.9</b>

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>December 31,</b>	<b>(in millions)</b>			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	\$ —	\$ —	\$ 92.0	\$ 62.3
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.0)	(2.1)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(10.2)	(9.8)	(22.5)	(27.3)
<b>Funded (Underfunded) Status</b>	<b>\$ (10.2)</b>	<b>\$ (9.8)</b>	<b>\$ 67.5</b>	<b>\$ 32.9</b>

**I&M**

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Change in Benefit Obligation</b>	<b>(in millions)</b>			
Benefit Obligation as of January 1,	\$ 567.0	\$ 624.3	\$ 138.3	\$ 153.5
Service Cost	13.4	13.6	1.4	1.6
Interest Cost	23.8	22.1	5.8	5.4
Actuarial (Gain) Loss	49.8	(53.9)	8.1	(10.6)
Plan Amendments	—	—	(1.5)	—
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
Participant Contributions	—	—	4.4	4.5
Medicare Subsidy	—	—	—	0.1
<b>Benefit Obligation as of December 31,</b>	<b>\$ 616.1</b>	<b>\$ 567.0</b>	<b>\$ 142.9</b>	<b>\$ 138.3</b>

<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 583.8	\$ 636.7	\$ 187.3	\$ 211.1
Actual Gain (Loss) on Plan Assets	84.6	(13.8)	38.2	(12.1)
Company Contributions	—	—	—	—
Participant Contributions	—	—	4.4	4.5
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 630.5</b>	<b>\$ 583.8</b>	<b>\$ 216.3</b>	<b>\$ 187.3</b>

<b>Funded Status as of December 31,</b>	<b>\$ 14.4</b>	<b>\$ 16.8</b>	<b>\$ 73.4</b>	<b>\$ 49.0</b>
---	----------------	----------------	----------------	----------------

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>I&amp;M</b>	<b>December 31,</b>			
	<b>(in millions)</b>			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	\$ 15.8	\$ 18.0	\$ 73.4	\$ 49.0
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.4)	(1.2)	—	—
<b>Funded Status</b>	<b>\$ 14.4</b>	<b>\$ 16.8</b>	<b>\$ 73.4</b>	<b>\$ 49.0</b>

<u>OPCo</u>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Change in Benefit Obligation</b>	<b>(in millions)</b>			
Benefit Obligation as of January 1,	\$ 453.9	\$ 501.1	\$ 129.5	\$ 144.3
Service Cost	7.9	7.7	0.8	0.9
Interest Cost	19.1	17.7	5.5	5.1
Actuarial (Gain) Loss	40.5	(36.6)	4.9	(9.4)
Plan Amendments	—	—	(1.2)	—
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
Participant Contributions	—	—	4.1	4.3
Medicare Subsidy	—	—	0.1	0.1
<b>Benefit Obligation as of December 31,</b>	<b>\$ 487.8</b>	<b>\$ 453.9</b>	<b>\$ 130.2</b>	<b>\$ 129.5</b>
<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 466.1	\$ 509.1	\$ 175.4	\$ 198.5
Actual Gain (Loss) on Plan Assets	66.6	(7.0)	31.1	(11.6)
Participant Contributions	—	—	4.1	4.3
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 499.1</b>	<b>\$ 466.1</b>	<b>\$ 197.1</b>	<b>\$ 175.4</b>
<b>Funded Status as of December 31,</b>	<b>\$ 11.3</b>	<b>\$ 12.2</b>	<b>\$ 66.9</b>	<b>\$ 45.9</b>

<u>OPCo</u>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>December 31,</b>			
	<b>(in millions)</b>			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	\$ 11.7	\$ 12.6	\$ 66.9	\$ 45.9
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(0.4)	—	—
<b>Funded Status</b>	<b>\$ 11.3</b>	<b>\$ 12.2</b>	<b>\$ 66.9</b>	<b>\$ 45.9</b>

**PSO**

	Pension Plans		OPEB	
	2019	2018	2019	2018
<b>Change in Benefit Obligation</b>	(in millions)			
Benefit Obligation as of January 1,	\$ 253.8	\$ 276.6	\$ 62.3	\$ 69.4
Service Cost	6.5	7.0	0.6	0.7
Interest Cost	10.6	9.9	2.6	2.5
Actuarial (Gain) Loss	16.8	(18.9)	3.8	(5.6)
Plan Amendments	—	—	(0.7)	—
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
Participant Contributions	—	—	2.0	2.0
<b>Benefit Obligation as of December 31,</b>	<b>\$ 267.5</b>	<b>\$ 253.8</b>	<b>\$ 64.7</b>	<b>\$ 62.3</b>
<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 261.2	\$ 287.8	\$ 84.3	\$ 95.5
Actual Gain (Loss) on Plan Assets	34.7	(5.9)	17.6	(9.2)
Company Contributions	0.5	0.1	—	2.7
Participant Contributions	—	—	2.0	2.0
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 276.2</b>	<b>\$ 261.2</b>	<b>\$ 98.0</b>	<b>\$ 84.3</b>
<b>Funded Status as of December 31,</b>	<b>\$ 8.7</b>	<b>\$ 7.4</b>	<b>\$ 33.3</b>	<b>\$ 22.0</b>

	Pension Plans		OPEB	
	2019	2018	2019	2018
<b>PSO</b>	December 31,			
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	\$ 10.6	\$ 9.7	\$ 33.3	\$ 22.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.8)	(2.1)	—	—
<b>Funded Status</b>	<b>\$ 8.7</b>	<b>\$ 7.4</b>	<b>\$ 33.3</b>	<b>\$ 22.0</b>

**SWEPCo**

	Pension Plans		OPEB	
	2019	2018	2019	2018
<b>Change in Benefit Obligation</b>				
	(in millions)			
Benefit Obligation as of January 1,	\$ 291.4	\$ 314.6	\$ 72.7	\$ 80.3
Service Cost	8.6	9.3	0.8	0.9
Interest Cost	12.4	11.3	3.1	2.8
Actuarial (Gain) Loss	25.5	(19.2)	6.0	(5.9)
Plan Amendments	—	—	(0.8)	—
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
Participant Contributions	—	—	2.2	2.3
<b>Benefit Obligation as of December 31,</b>	<b>\$ 314.2</b>	<b>\$ 291.4</b>	<b>\$ 77.4</b>	<b>\$ 72.7</b>
<b>Change in Fair Value of Plan Assets</b>				
Fair Value of Plan Assets as of January 1,	\$ 281.0	\$ 311.7	\$ 98.5	\$ 110.4
Actual Gain (Loss) on Plan Assets	39.5	(7.3)	23.1	(9.2)
Company Contributions	0.1	1.2	—	2.7
Participant Contributions	—	—	2.2	2.3
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
<b>Fair Value of Plan Assets as of December 31,</b>	<b>\$ 296.9</b>	<b>\$ 281.0</b>	<b>\$ 117.2</b>	<b>\$ 98.5</b>
<b>Funded (Underfunded) Status as of December 31,</b>	<b>\$ (17.3)</b>	<b>\$ (10.4)</b>	<b>\$ 39.8</b>	<b>\$ 25.8</b>

	Pension Plans		OPEB	
	2019	2018	2019	2018
<b>December 31,</b>				
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	\$ —	\$ —	\$ 39.8	\$ 25.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(17.2)	(10.2)	—	—
<b>Funded (Underfunded) Status</b>	<b>\$ (17.3)</b>	<b>\$ (10.4)</b>	<b>\$ 39.8</b>	<b>\$ 25.8</b>

***Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI***

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

<u>AEP</u>	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
Components	(in millions)			
Net Actuarial Loss	\$ 1,406.2	\$ 1,355.2	\$ 225.8	\$ 419.8
Prior Service Cost (Credit)	0.2	—	(285.7)	(347.2)
Recorded as				
Regulatory Assets	\$ 1,351.8	\$ 1,267.9	\$ (46.8)	\$ 52.5
Deferred Income Taxes	11.5	18.4	(2.7)	4.2
Net of Tax AOCI	43.1	68.9	(10.4)	15.9

<b><u>Components</u></b>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>(in millions)</b>			
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
Actuarial (Gain) Loss During the Year	\$ 108.6	\$ 88.8	\$ (171.9)	\$ 120.4
Amortization of Actuarial Loss	(57.6)	(87.8)	(22.1)	(10.5)
Prior Service (Credit) Cost	0.2	—	(7.6)	—
Amortization of Prior Service Credit	—	—	69.1	69.1
<b>Change for the Year Ended December 31,</b>	<b>\$ 51.2</b>	<b>\$ 1.0</b>	<b>\$ (132.5)</b>	<b>\$ 179.0</b>

<u>AEP Texas</u>	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
Components	(in millions)			
Net Actuarial Loss	\$ 184.7	\$ 182.0	\$ 23.5	\$ 38.0
Prior Service Credit	—	—	(24.2)	(29.5)
Recorded as				
Regulatory Assets	\$ 172.2	\$ 168.2	\$ (0.2)	\$ 8.7
Deferred Income Taxes	2.7	2.9	(0.1)	—
Net of Tax AOCI	9.8	10.9	(0.4)	(0.2)

<b><u>Components</u></b>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>(in millions)</b>			
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>

Actuarial (Gain) Loss During the Year	\$	7.6	\$	14.0	\$	(12.7)	\$	14.9
Amortization of Actuarial Loss		(4.9)		(7.2)		(1.8)		(0.8)
Prior Service Credit		—		—		(0.6)		—
Amortization of Prior Service Credit		—		—		5.9		5.9
<b>Change for the Year Ended December 31,</b>	<b>\$</b>	<b>2.7</b>	<b>\$</b>	<b>6.8</b>	<b>\$</b>	<b>(9.2)</b>	<b>\$</b>	<b>20.0</b>

**APCo**

APCo	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in millions)			
Components				
Net Actuarial Loss	\$ 168.3	\$ 172.2	\$ 28.8	\$ 58.9
Prior Service Credit	—	—	(41.6)	(50.4)
Recorded as				
Regulatory Assets	\$ 166.3	\$ 169.6	\$ (5.5)	\$ 2.6
Deferred Income Taxes	0.3	0.5	(1.5)	1.2
Net of Tax AOCI	1.7	2.1	(5.8)	4.7

**APCo**

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>(in millions)</b>			
Actuarial (Gain) Loss During the Year	\$ 3.1	\$ 0.3	\$ (26.4)	\$ 12.8
Amortization of Actuarial Loss	(7.0)	(10.6)	(3.7)	(1.9)
Prior Service Credit	—	—	(1.3)	—
Amortization of Prior Service Credit	—	—	10.1	10.0
<b>Change for the Year Ended December 31,</b>	<b>\$ (3.9)</b>	<b>\$ (10.3)</b>	<b>\$ (21.3)</b>	<b>\$ 20.9</b>

**I&M**

<b>I&amp;M</b>	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>December 31,</b>			
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Components</b>	<b>(in millions)</b>			
Net Actuarial Loss	\$ 76.0	\$ 80.6	\$ 32.7	\$ 54.7
Prior Service Credit	—	—	(39.0)	(47.4)
<b>Recorded as</b>				
Regulatory Assets	\$ 73.7	\$ 78.4	\$ (6.2)	\$ 6.5
Deferred Income Taxes	0.5	0.5	—	0.2
Net of Tax AOCI	1.8	1.7	(0.1)	0.6

**I&M**

	<b>Pension Plans</b>		<b>OPEB</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
	<b>(in millions)</b>			
Actuarial (Gain) Loss During the Year	\$ 2.0	\$ (4.5)	\$ (19.3)	\$ 13.9
Amortization of Actuarial Loss	(6.6)	(9.8)	(2.7)	(1.2)
Prior Service Credit	—	—	(1.0)	—

Amortization of Prior Service Credit	<u>—</u>	<u>—</u>	<u>9.4</u>	<u>9.5</u>
<b>Change for the Year Ended December 31,</b>	<u><u>\$ (4.6)</u></u>	<u><u>\$ (14.3)</u></u>	<u><u>\$ (13.6)</u></u>	<u><u>\$ 22.2</u></u>

**OPCo**

OPCo	Pension Plans				OPEB			
	December 31,							
	2019	2018	2019	2018				
	(in millions)							
Components								
Net Actuarial Loss	\$	178.7	\$	180.7	\$	17.2	\$	35.5
Prior Service Credit		—		—		(28.6)		(34.7)
Recorded as								
Regulatory Assets	\$	178.7	\$	180.7	\$	(11.4)	\$	0.8

**OPCo**

	Pension Plans		OPEB	
	2019	2018	2019	2018
Components	(in millions)			
Actuarial (Gain) Loss During the Year	\$ 3.3	\$ (0.9)	\$ (15.8)	\$ 14.0
Amortization of Actuarial Loss	(5.3)	(8.0)	(2.5)	(1.1)
Prior Service Credit	—	—	(0.8)	—
Amortization of Prior Service Credit	—	—	6.9	6.9
Change for the Year Ended December 31,	<u>\$ (2.0)</u>	<u>\$ (8.9)</u>	<u>\$ (12.2)</u>	<u>\$ 19.8</u>

**PSO**

<u>PSO</u>	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in millions)			
Components				
Net Actuarial Loss	\$ 73.0	\$ 77.6	\$ 18.2	\$ 28.3
Prior Service Credit	—	—	(17.8)	(21.6)
Recorded as				
Regulatory Assets	\$ 73.0	\$ 77.6	\$ 0.4	\$ 6.7

**PSO**

	Pension Plans		OPEB	
	2019	2018	2019	2018
Components	(in millions)			
Actuarial (Gain) Loss During the Year	\$ (1.7)	\$ 3.2	\$ (8.9)	\$ 9.0
Amortization of Actuarial Loss	(2.9)	(4.4)	(1.2)	(0.5)
Prior Service Credit	—	—	(0.5)	—
Amortization of Prior Service Credit	—	—	4.3	4.3
Change for the Year Ended December 31,	<u>\$ (4.6)</u>	<u>\$ (1.2)</u>	<u>\$ (6.3)</u>	<u>\$ 12.8</u>



<u>SWEPCo</u>	<u>Pension Plans</u>		<u>OPEB</u>	
	<u>December 31,</u>			
	<u>2019</u>	<u>2018</u>	<u>2019</u>	<u>2018</u>
<u>Components</u>	<u>(in millions)</u>			
Net Actuarial Loss	\$ 97.8	\$ 97.4	\$ 21.1	\$ 33.9
Prior Service Credit	—	—	(21.6)	(26.2)
<u>Recorded as</u>				
Regulatory Assets	\$ 97.8	\$ 97.4	\$ —	\$ 4.9
Deferred Income Taxes	—	—	—	0.7
Net of Tax AOCI	—	—	(0.5)	2.1

<u>SWEPCo</u>	<u>Pension Plans</u>		<u>OPEB</u>	
	<u>2019</u>	<u>2018</u>	<u>2019</u>	<u>2018</u>
	<u>(in millions)</u>			
Actuarial (Gain) Loss During the Year	\$ 3.8	\$ 5.5	\$ (11.4)	\$ 9.8
Amortization of Actuarial Loss	(3.4)	(5.5)	(1.4)	(0.6)
Prior Service Credit	—	—	(0.6)	—
Amortization of Prior Service Credit	—	—	5.2	5.2
<b>Change for the Year Ended December 31,</b>	<b>\$ 0.4</b>	<b>\$ —</b>	<b>\$ (8.2)</b>	<b>\$ 14.4</b>

### *Determination of Pension Expense*

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

### *Pension and OPEB Assets*

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

Company	Pension Plan		OPEB	
	December 31,			
	2019	2018	2019	2018
AEP Texas	8.7%	8.7%	8.3%	8.5%
APCo	12.7%	12.6%	15.2%	15.5%
I&M	12.6%	12.4%	12.1%	12.2%
OPCo	10.0%	9.9%	11.1%	11.4%
PSO	5.5%	5.6%	5.5%	5.5%

SWEPCo	5.9%	6.0%	6.6%	6.4%
--------	------	------	------	------

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities (a):						
Domestic	\$ 387.8	\$ —	\$ —	\$ —	\$ 387.8	7.8 %
International	609.1	—	—	—	609.1	12.1 %
Common Collective Trusts (c)	—	—	—	547.3	547.3	10.9 %
Subtotal – Equities	996.9	—	—	547.3	1,544.2	30.8 %
Fixed Income (a):						
United States Government and Agency Securities	(5.8)	1,248.6	—	—	1,242.8	24.8 %
Corporate Debt	—	1,143.7	—	—	1,143.7	22.8 %
Foreign Debt	—	211.6	—	—	211.6	4.2 %
State and Local Government	—	55.1	—	—	55.1	1.1 %
Other – Asset Backed	—	3.6	—	—	3.6	0.1 %
Subtotal – Fixed Income	(5.8)	2,662.6	—	—	2,656.8	53.0 %
Infrastructure (c)	—	—	—	85.8	85.8	1.7 %
Real Estate (c)	—	—	—	239.4	239.4	4.8 %
Alternative Investments (c)	—	—	—	448.3	448.3	8.9 %
Cash and Cash Equivalents (c)	—	24.4	—	37.2	61.6	1.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(20.7)	(20.7)	(0.4)%
<b>Total</b>	<b>\$ 991.1</b>	<b>\$ 2,687.0</b>	<b>\$ —</b>	<b>\$ 1,337.3</b>	<b>\$ 5,015.4</b>	<b>100.0 %</b>

- (a) Includes investment securities loaned to borrowers under the securities lending program. See the “Investments Held in Trust for Future Liabilities” section of Note 1 for additional information.
- (b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
- (c) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	\$ 312.2	\$ —	\$ —	\$ —	\$ 312.2	17.5%
International	251.5	—	—	—	251.5	14.1%
Common Collective Trusts (b)	—	—	—	260.8	260.8	14.7%
Subtotal – Equities	563.7	—	—	260.8	824.5	46.3%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	177.6	177.6	10.0%
United States Government and Agency Securities	(0.1)	214.4	—	—	214.3	12.0%
Corporate Debt	—	206.7	—	—	206.7	11.6%
Foreign Debt	—	35.5	—	—	35.5	2.0%
State and Local Government	58.8	14.8	—	—	73.6	4.1%
Other – Asset Backed	—	0.2	—	—	0.2	—%
Subtotal – Fixed Income	58.7	471.6	—	177.6	707.9	39.7%
Trust Owned Life Insurance:						
International Equities	—	60.2	—	—	60.2	3.4%
United States Bonds	—	151.6	—	—	151.6	8.5%
Subtotal – Trust Owned Life Insurance	—	211.8	—	—	211.8	11.9%
Cash and Cash Equivalents (b)	26.7	—	—	6.7	33.4	1.9%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.2	4.2	0.2%
<b>Total</b>	<b>\$ 649.1</b>	<b>\$ 683.4</b>	<b>\$ —</b>	<b>\$ 449.3</b>	<b>\$ 1,781.8</b>	<b>100.0%</b>

- (a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.  
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities (a):						
Domestic	\$ 277.3	\$ —	\$ —	\$ —	\$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
<b>Total</b>	<b>\$ 661.2</b>	<b>\$ 2,907.2</b>	<b>\$ —</b>	<b>\$ 1,127.5</b>	<b>\$ 4,695.9</b>	<b>100.0%</b>

- (a) Includes investment securities loaned to borrowers under the securities lending program. See the “Investments Held in Trust for Future Liabilities” section of Note 1 for additional information.
- (b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
- (c) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	\$ 233.3	\$ —	\$ —	\$ —	\$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	—%
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
<b>Total</b>	<b>\$ 515.6</b>	<b>\$ 625.2</b>	<b>\$ —</b>	<b>\$ 393.4</b>	<b>\$ 1,534.2</b>	<b>100.0 %</b>

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

### ***Accumulated Benefit Obligation***

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	\$ 4,929.0	\$ 417.5	\$ 627.3	\$ 586.3	\$ 464.2	\$ 248.9	\$ 291.9
Nonqualified Pension Plans	69.7	3.6	0.2	0.6	0.1	1.6	1.3
<b>Total as of December 31, 2019</b>	<b>\$ 4,998.7</b>	<b>\$ 421.1</b>	<b>\$ 627.5</b>	<b>\$ 586.9</b>	<b>\$ 464.3</b>	<b>\$ 250.5</b>	<b>\$ 293.2</b>

<u>Accumulated Benefit Obligation</u>	<u>AEP</u>	<u>AEP Texas</u>	<u>APCo</u>	<u>I&amp;M</u>	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>
	<b>(in millions)</b>						
Qualified Pension Plan	\$ 4,560.7	\$ 393.2	\$ 588.3	\$ 536.3	\$ 438.3	\$ 238.0	\$ 271.6
Nonqualified Pension Plans	64.9	3.6	0.2	0.6	0.2	2.2	1.2
<b>Total as of December 31, 2018</b>	<u><u>\$ 4,625.6</u></u>	<u><u>\$ 396.8</u></u>	<u><u>\$ 588.5</u></u>	<u><u>\$ 536.9</u></u>	<u><u>\$ 438.5</u></u>	<u><u>\$ 240.2</u></u>	<u><u>\$ 272.8</u></u>

## Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

### Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Projected Benefit Obligation	\$ 5,236.8	\$ 441.2	\$ 647.2	\$ 1.5	\$ 0.4	\$ 1.9	\$ 314.2
Fair Value of Plan Assets	5,015.4	435.1	637.0	—	—	—	296.9
<b>Underfunded Projected Benefit Obligation as of December 31, 2019</b>	<b>\$ (221.4)</b>	<b>\$ (6.1)</b>	<b>\$ (10.2)</b>	<b>\$ (1.5)</b>	<b>\$ (0.4)</b>	<b>\$ (1.9)</b>	<b>\$ (17.3)</b>
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Projected Benefit Obligation	\$ 4,810.3	\$ 3.8	\$ 603.1	\$ 1.2	\$ 0.4	\$ 2.3	\$ 291.4
Fair Value of Plan Assets	4,695.9	—	593.3	—	—	—	281.0
<b>Underfunded Projected Benefit Obligation as of December 31, 2018</b>	<b>\$ (114.4)</b>	<b>\$ (3.8)</b>	<b>\$ (9.8)</b>	<b>\$ (1.2)</b>	<b>\$ (0.4)</b>	<b>\$ (2.3)</b>	<b>\$ (10.4)</b>

### Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Accumulated Benefit Obligation	\$ 69.7	\$ 3.6	\$ 0.2	\$ 0.6	\$ 0.1	\$ 1.6	\$ 1.3
Fair Value of Plan Assets	—	—	—	—	—	—	—
<b>Underfunded Accumulated Benefit Obligation as of December 31, 2019</b>	<b>\$ (69.7)</b>	<b>\$ (3.6)</b>	<b>\$ (0.2)</b>	<b>\$ (0.6)</b>	<b>\$ (0.1)</b>	<b>\$ (1.6)</b>	<b>\$ (1.3)</b>
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Accumulated Benefit Obligation	\$ 64.9	\$ 3.6	\$ 0.2	\$ 0.6	\$ 0.2	\$ 2.2	\$ 1.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
<b>Underfunded Accumulated Benefit Obligation as of December 31, 2018</b>	<b>\$ (64.9)</b>	<b>\$ (3.6)</b>	<b>\$ (0.2)</b>	<b>\$ (0.6)</b>	<b>\$ (0.2)</b>	<b>\$ (2.2)</b>	<b>\$ (1.2)</b>

### Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2020:

Company	Pension Plans	OPEB
	(in millions)	
AEP	\$ 6.1	\$ 3.4
AEP Texas	0.4	0.1

APCo	—	2.0
I&M	—	—
OPCo	—	—
PSO	0.1	—
SWEPCo	0.1	—